2022 CALIFORNIA ELECTRIC AND GAS UTILITY COSTS REPORT

AB 67 Annual Report to the Governor and Legislature

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California Public Utilities Commission

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Executive Summary

The California Public Utilities Commission (CPUC) issues the Assembly Bill (AB) 67 Annual Report (referred to as the 2022 California Electric and Gas Utility Costs Report) pursuant to California Public Utilities Code Section 913, which requires the CPUC to publish the costs to ratepayers of all utility programs and activities currently recovered in retail rates.[1]

The 2022 California Electric and Gas Utility Costs Report, published in 2023, provides a detailed narrative and transparency into factors driving electric and gas rates for 2022 activities.

Key electric highlights from this report include:

- Compared to 2021, the 2022 CPUC-authorized annual revenue requirement for Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) decreased by 1.6 percent and 2.8 percent, respectively, and increased for Southern California Edison (SCE) by 5.6 percent.
    - Compared to 2021, the 2022 generation costs decreased for PG&E, SCE, and SDG&E by 9.7 percent, 2.8 percent, and 20.2 percent, respectively. The decreases were driven by customer departures to Customer Choice Aggregators, which reduced the number of utility bundled customers. Due to fixed costs and high prices per megawatt hour, generation costs rose on a per customer basis for those remaining on bundled service.
    - During the same time period, distribution costs increased for PG&E, SCE, and SDG&E by 26.4 percent, 24.9 percent, and 1.6 percent, respectively. Electric generation and distribution are the largest components of electric rates, and collectively account for approximately 75 percent of the utilities' electric rates.
- Compared to 2021, the 2022 transmission costs increased for PG&E, SCE, and SDG&E by 44.9 percent, 10.9 percent, and 5.0 percent, respectively.
- In Federal Energy Regulatory Commission (FERC) proceedings for transmission owner (TO) rate cases from 2008 to 2022, the CPUC has successfully negotiated a reduction to the transmission revenue requirements resulting in a cumulative savings of approximately $3.6 billion for California ratepayers.

[1] Section 913 reporting requirements apply to electrical corporations with at least 1,000,000 retail customers in California and gas corporations with at least 500,000 retail customers in California.

- In 2022, the electric California investor-owned utilities collectively included approximately $383 million in direct greenhouse gas Cap-and-Trade Program costs in rates but provided bundled ratepayers approximately $910 million (with another $415 million to unbundled customers) in credits from sale of California Air Resources Board (CARB)-allocated carbon allowances at auction.
- In 2022, Demand-Side Management program[2] costs, when combined, accounted for 8.8 percent of the total electric revenue requirement for the electric investor owned utilities (IOUs) in California (PG&E, SCE, and SDG&E).
- Regulatory fees[3] in 2022 totaled approximately $680 million and accounted for roughly four percent of the annual revenue requirement for the electric IOUs (PG&E, SCE, and SDG&E).
- Increases in total system average rates generally tracked inflation for PG&E and SCE. SDG&E's average rates have been above the Consumer Price Index since 2009.

Key gas highlights from this report include:

- In 2022, total natural gas utility costs increased by 18.6 percent. The increase in natural gas costs was primarily driven by higher core[4] procurement costs, with smaller increases in transportation and Public Purchase Programs (PPP) costs.
- Core procurement costs increased primarily due to commodity prices. Gas market conditions, colder than average temperatures, and gas pipeline infrastructure and storage issues have put upward pressure on the price of gas.

[2] Demand-Side Management programs include programs such as Energy Efficiency, Energy Savings Assistance, California Alternative Rates for Energy (administrative costs only), Self-Generation Incentive Program, Demand Response, and Electric Program Investment Charge.

[3] Regulatory fees include a variety of charges levied by federal, state, and local governments.

[4] The typical natural gas utility customers in California are residential and small commercial customers, referred to as "core" customers.

I. Introduction

Enacted pursuant to AB 67 (Levine, Chapter 562, Statutes of 2005), California Public Utilities Code Section 913 requires the CPUC to prepare a written report on the costs of programs and activities conducted by the four major electric and gas companies regulated by the CPUC. This legislation was enacted in part to determine the effect of various legislative and administrative mandates, and to provide more transparency into factors driving electric and gas rates.

The report is to be submitted to the Governor and the Legislature by April 1st of each year and is required to include the following:

1. Each program mandated by statute and its annual cost to ratepayers.
2. Each program mandated by the CPUC and its annual cost to ratepayers.
3. Energy purchase contract costs and bond-related costs incurred pursuant to Division 27 of the Water Code (commonly known as Department of Water Resources (DWR) related costs).
4. All other aggregated categories of costs currently recovered in retail rates as determined by the CPUC.

This 2022 California Electric and Gas Utility Costs Report is submitted by the CPUC to fulfill these statutory requirements.

Background

The cost structures and the rate-setting process for California's utilities are inherently complex and can be difficult to track over time. To help create more transparency in the rate-setting process, the California Legislature passed AB 67 in 2005. AB 67 establishes an annual reporting requirement to identify the costs to ratepayers of all utility programs and activities currently recovered in retail rates. As in previous years, this report provides a detailed narrative of various energy policies in California, along with a breakdown of the underlying costs that drive electric and gas rates, including charts and tables showing how these costs and rates have varied since 2012.

The report presents an analysis of the CPUC-authorized revenue requirements for the four major California investor-owned utilities (IOUs or utilities): PG&E, SCE, SDG&E, and Southern California Gas Company (SoCalGas). Using sales forecasts, rates are set to collect these authorized revenue requirements. For certain utility programs, discrepancies between authorized revenue requirements and actual revenues and expenses are captured through balancing account mechanisms, which true-up the actual revenue to the authorized revenue requirement in the following year. This mitigates the risk of the utilities collecting more than or less than their authorized revenue requirements, particularly if sales are lower than forecast due to conservation, behind-the-meter solar, and efficiency programs.

Overview

Electric Utility Costs

- **Compared to 2022, the CPUC-authorized annual revenue requirements[5] for PG&E and SDG&E decreased by 1.6 percent and 2.8 percent, respectively, and increased for SCE by 5.6 percent.** The 2022 revenue requirement for the three electric utilities are shown in **Table 1.1**. The total company revenue requirement (including transmission)[6] for the electric utilities in 2022 is as follows: PG&E $15.1 billion, SCE $15.3 billion, and SDG&E $4.3 billion for a total of $34.7 billion.

Table 1.1: Electric Utility Revenue Requirement Comparison ($000)[7]

Utility	2022 CPUC	2021 CPUC	Difference ($000)	%	2022 Transmission	2022 Total Company
PG&E	12,156,983	12,349,288	(192,305)	(1.6)	2,948,943	15,105,926
SCE	13,880,415	13,141,517	738,897	5.6	1,390,045	15,270,459
SDG&E	3,498,824	3,598,631	(99,806)	(2.8)	772,822	4,271,646
Total	**29,536,222**	**29,089,436**	**446,786**	**1.5**	**5,111,810**	**34,648,032**

Much of the increase in SCE's revenue requirement is due to increased distribution related general rate case (GRC) costs such as operations and maintenance expenses for depreciated assets and wildfire safety improvements.[8]

- **Power procurement costs decreased for PG&E, SCE, and SDG&E during 2022.** Power procurement costs include the costs of generating and purchasing electricity as well as capital costs related to those items. **Table 1.2** shows the 2022 revenue requirement for the three electric utilities associated with generating and procuring electricity.

[5] All references to revenue requirements are to the CPUC-authorized annual revenue requirement and are in current dollars (not adjusted for inflation) unless otherwise indicated.

[6] The Federal Energy Regulatory Commission has jurisdiction over transmission-related revenue requirements.

[7] PG&E Advice Letter 6603-E/E-A, SCE Advice Letter 4864-E, and SDG&E Advice Letter 4004-E, effective 6/1/2022, 10/1/2021, and 6/1/2022, respectively.

[8] See Chapter II for a discussion on general rate cases revenue requirements.

Table 1.2: Electric Generation Revenue Requirement Comparison ($000)

Utility	2022	2021	Difference	
			$000	%
PG&E	4,670,136	5,073,429	(403,292)	(7.9)
SCE	5,124,938	5,237,899	(112,961)	(2.2)
SDG&E	1,138,195	1,417,182	(288,987)	(20.2)
Total	**10,933,269**	**11,738,510**	**(805,241)**	**(6.9)**

The decrease in PG&E's, SCE's, and SDG&E's generation revenue requirement from 2021 to 2022 is due to a growing percentage of the IOUs' load moving to service from Customer Choice Aggregators (CCAs), reducing the total load for which the IOUs must procure. In 2022, 31 percent of total IOU system load was served by CCAs. However, due to high fixed costs and high prices per megawatt hour for those customers remaining with service from the utility in 2021, generation rates rose on a per customer basis.

For additional analysis, see Chapter IV.

- **Electric distribution costs increased for PG&E, SCE, and SDG&E.** Distribution costs include the costs of providing service below a certain voltage (60 kilovolt (kV), 200 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are regulated by the CPUC. **Table 1.3** shows the 2022 revenue requirement for the three electric utilities associated with distribution of energy through the electric grid.

Table 1.3: Electric Distribution Revenue Requirement Comparison ($000)

Utility	2022	2021	Difference	
			$000	%
PG&E	6,928,792	5,595,486	1,333,306	23.8
SCE	8,225,321	6,587,686	1,637,634	24.9
SDG&E	1,624,992	1,599,694	25,298	1.6
Total	**16,779,105**	**13,782,867**	**2,996,238**	**21.7**

PG&E's, SCE's and SDG&E's increase can be attributed to an increase in distribution related expenses approved in PG&E's 2020 GRC, SCE's 2021 GRC, and SDG&E's 2019 GRC. For additional analysis, see Chapter III.

- **Compared to 2021, electric transmission costs passed onto ratepayers increased for PG&E, SCE, and SDG&E.** Transmission rates include the costs of providing service above a certain voltage (60 kV, 200 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are part of the electric grid controlled by the California Independent System Operator (CAISO) and regulated by the Federal Energy

Regulatory Commission (FERC). **Table 1.4** shows the 2022 electric transmission costs compared to 2021 for the three investor-owned utilities.

Table 1.4: Electric Transmission Cost Comparison ($000)

Utility	2022	2021	Difference	
			$000	%
PG&E	2,948,943	2,035,538	913,405	44.9
SCE	1,390,045	1,253,026	137,019	10.9
SDG&E	772,822	736,175	36,647	5.0
Total	**5,111,810**	**4,024,739**	**1,087,071**	**27.0**

PG&E's 44.9 percent increase in transmission costs in 2022 reflects the historic upward trend of transmission costs, which was interrupted in 2021 by downward adjustments for past over-collections related to rate case settlements. The revenue requirement in PG&E's transmission owner rate case at FERC increased by over $660 million in 2022.[9] PG&E attributes this increase primarily to Operations and Maintenance (O&M) expenses including wildfire prevention costs such as vegetation management, and other upgrades for grid operations such as Work at the Request of Others (WRO). The increase in WRO costs is a result of delays in projects that were previously forecasted to be operational before 2022 and to new network upgrade project requests. Further, in 2022, the Transmission Access Charge Balancing Account Adjustment included over $300 million in costs related to under-collection at the CAISO for others' use of the PG&E transmission grid. SCE's increase in transmission costs relates to a large upward adjustment to its 2017/2018 wildfires/mudslides reserve and a large year-over-year increase in plant and construction work in progress (CWIP) plant balances[10]. SDG&E's increase is related to: 1) higher O&M costs, especially maintenance costs of overhead and underground lines; depreciation expenses; and property and payroll taxes, and 2) an increase in the transmission rate base of approximately $260 million, or 6 percent[11]. For additional analysis, see Chapter III.

- **Public Purpose Program costs decreased for PG&E and increased for SCE and SDG&E, since 2021.** These Public Purpose Programs (PPPs) include Energy Efficiency, Energy Savings Assistance, and California Alternative Rates for Energy (CARE) among other programs like the Schools Energy Efficiency Program (SEEP), created pursuant to AB 841. The primary driver of the increase in PPP costs from 2021-2022

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[9] It is worth noting that as a result of the settlement in PG&E's TO20 transmission owner rate case in 2020, costs to PG&E's ratepayers, while high, are hundreds of millions of dollars less than they otherwise would have been if PG&E's as-filed formula were in effect.

[10] The SCE rate case is an annual update filing as required by the FERC settlement in SCE TO2019A, FERC Docket ER19-1553.

[11] SDG&E's TO5 Cycle 4 Formula Rate Filing, TO5-Cycle 4, Transmittal Letter, December 1, 2021.

include a significant increase in CARE collections. **Table 1.5** shows the 2021 and 2022 revenue requirement for the three electric utilities associated with PPPs.

Table 1.5: Electric PPP Revenue Requirement Comparison ($000)

Utility	2022	2021	Difference	
			$000	%
PG&E	389,022	467,964	(78,942)	(16.9)
SCE	646,982	426,011	220,971	51.9
SDG&E	681,337	265,797	415,540	156.3
Total	**1,717,341**	**1,159,772**	**557,569**	**48.1**

- **Bonds and Regulatory Fees (including nuclear decommissioning revenue requirements) increased for PG&E, SCE, and SDG&E during 2022.** During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. These bonds were retired in September 2020. Beginning October 1, 2020, the related revenue requirements have been substantively replaced by charges to support the AB 1054 Wildfire Fund. Fees include a variety of charges levied by federal, state, and local governments. Fees are included as specific components of other revenue requirements, except for nuclear decommissioning costs, which are recovered by the Nuclear Decommissioning Adjustment Mechanism (NDAM). **Table 1.6** shows the 2022 revenue requirements for the three electric utilities associated with bonds and nuclear decommissioning activities.

Table 1.6: Bonds and Fees Revenue Requirement Comparison ($000)

Utility	2022	2021	Difference	
			$000	%
PG&E	574,144	1,054,517	(480,373)	(45.6)
SCE	410,758	555,534	(144,776)	(26.1)
SDG&E	54,300	95,985	(41,686)	(43.4)
Total	**1,039,201**	**1,706,037**	**(666,835)**	**(39.1)**

During 2022, much of the variation in the revenue requirements for bonds and assorted fees was driven by the Wildfire Fund Non-Bypassable Charge. For additional analysis, see Chapter VI.

- **The revenue requirements for PG&E, SCE, and SDG&E increased in 2022 due to adjustments for amortizations of balances in balancing and/or memorandum accounts. Table 1.7** shows the effects of these adjustments on the revenue requirements for the electric utilities.

Table 1.7: Adjustments to the 2022 Revenue Requirement ($000)

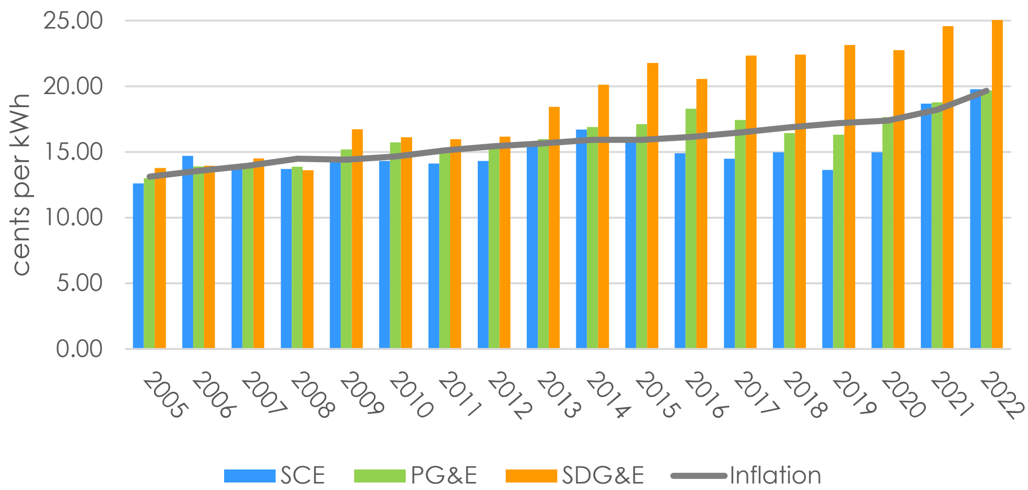
Utility	Forecasted 2022 Costs	Amortization Adjustments	Authorized 2022 Revenue Requirement	Difference %
PG&E	11,465,380	691,604	12,156,984	6.0%
SCE	12,970,743	909,672	13,880,415	7.0%
SDG&E	3,191,856	306,968	3,498,824	9.6%
Total	**27,627,979**	**1,908,243**	**29,536,222**	**6.9%**

Utilities add amortizations of balancing and/or memorandum accounts to the annual revenue requirement to recover costs of prior years and set rates incorporating this adjustment. The information in this report refers to the adjusted annual revenue requirement to show the annual cost to ratepayers.

- **Increases in System Average Rates generally tracked inflation, except for SDG&E. SDG&E's average rates have been above the Consumer Price Index (CPI) since 2009 (Figure 1.1).** From 2018 to 2022, system average rates across the three electric IOUs have increased at an annual average of approximately 5.2 percent (**Table 1.8**), which is above the average annual inflation rate of 3.6 percent over the same time period. In 2022, SCE's system average rate was 19.76 cents per kilowatt hour (¢/kWh), PG&E's was 19.67 ¢/kWh, and SDG&E's was 25.09 ¢/kWh.[12] To show the effect of inflation from 2005 – 2022, the average of all three utilities' system average rates in 2005, adjusted for inflation to 2022 nominal dollars, is 19.66 ¢/kWh. The average of all three utilities' system average rates for 2022 is 21.51 ¢/kWh, which suggests that the cost of electricity to the ratepayer generally increased by 1.85 ¢/kWh since 2005 when excluding the effects of inflation.

[12] PG&E Advice Letter 6603-E/E-A, SCE Advice Letter 4864-E, and SDG&E Advice Letter 4004-E, effective 6/01/2022, 10/1/2022, and 6/01/2022, respectively.

Figure 1.1: Trends in Electric Total System Average Rates (2005-2022)[13]



Annual Inflation Rate (2013-2022)[14]										
2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average (2018-2022)
1.5%	1.6%	0.1%	1.3%	2.1%	2.4%	1.8%	1.2%	4.7%	8.0%	**3.6%**

Table 1.8: Annual Change in Electric Total System Average Rates (2018-2022)

Utility	2018	2019		2020		2021		2022		Average
	Rate	Rate	% Change	Rate	% Change	Rate	% Change	Rate	% Change	% Change
SCE	14.96	13.62	(8.9)	14.97	9.9	18.68	24.8	19.76	5.8	7.9
PG&E	16.43	16.30	(0.8)	17.65	8.3	18.78	6.4	19.67	4.7	4.7
SDG&E	22.40	23.13	3.3	22.75	(1.7)	24.58	8.1	25.09	2.1	2.9

- **For SDG&E, system average rates have generally trended above inflation since 2009.** All three utilities have experienced declines in kWh sales, which also lead to increased system average rates when the revenue requirement remains flat or rises. The increase in average rates for PG&E, SCE, and SDG&E in 2022 is due to an increase in distribution costs.

[13] Total System Average Rates reflect total authorized revenue requirement and total forecasted sales for both bundled and unbundled customers.

[14] Source: Bureau of Labor Statistics, CPI-All Urban Consumers.

- **Electric generation and distribution are the largest components of electric rates.** As shown in **Figure 1.2** and **Table 1.9**, utility-owned generation and purchased power sources, plus distribution, collectively account for approximately 75 percent of the utilities' electric rates.

Figure 1.2: 2022 System Average Electric Rate Components

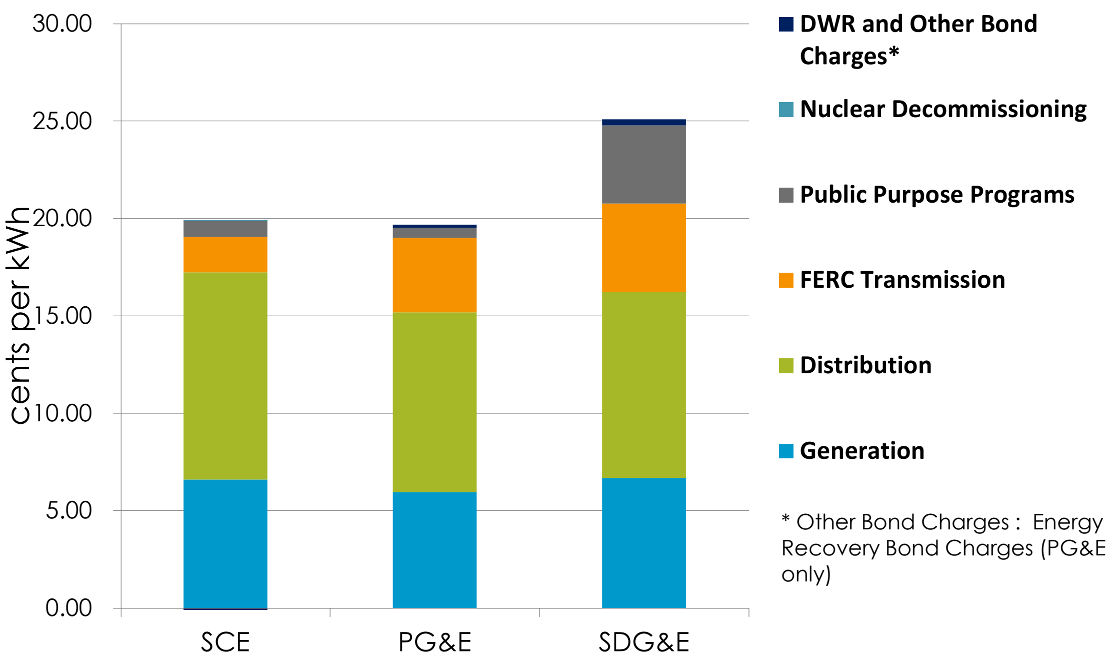


Table 1.9: 2022 System Average Electric Rate Component Values (¢/kWh)

Rate Component	SCE	PG&E	SDG&E
Generation	6.63	6.08	6.69
Distribution	10.65	9.02	9.54
FERC Transmission	1.80	3.84	4.54
Public Purpose Program	0.84	0.51	4.00
Nuclear Decommissioning	0.01	0.06	0.01
DWR and Other Bond Charges	(0.16)	0.16	0.31
Total	**19.76**	**19.67**	**25.09**

Gas Utility Costs

- **In 2022, total natural gas revenue requirement increased by 18.6 percent from 2021, a greater increase than the 10.8 percent increase seen from 2020 to 2021.**The increase in the 2022 gas utility revenue requirement is a result of a substantial increase in core procurement costs as well as smaller increases in transportation and Public Purpose Program (PPP) costs. Gas market conditions, cold winter weather, and gas pipeline and storage issues have contributed to the increased commodity prices. See Chapter VII for a discussion of gas utility costs.

The remainder of this report provides a breakdown of the various electric and natural gas revenue requirement components and identifies the sources of the greatest increases in costs. Chapters II through VI address electric revenue requirements and Chapter VII addresses natural gas revenue requirements. In addition to the detailed summary tables provided throughout the text, Appendix A and Appendix B provide summaries of each IOU's authorized revenue requirements organized by the rate components typically shown on customer bills.

II. Determining Revenue Requirements

Due to the increasingly varied nature of utility costs and the multitude of energy policy programs, the determination of the funds needed for utility service and the rate-setting process at the CPUC have grown more complex over time. The following venues are used to determine the revenues that the utilities are authorized to collect through rates:

1. **General Rate Cases (GRCs):** GRCs for the large energy utilities occurred on a three-year cycle at the CPUC in the past; however, utilities are transitioning to a four-year cycle based on Decision (D.) 20-01-002. In GRCs, the CPUC evaluates the regulated operations of the utilities and determines the reasonableness of utility requests for changes in revenue needed to fund utility service. For PG&E, SCE, and SDG&E, the GRCs are divided into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect (also called the "revenue requirement"), while Phase II determines the share of the utility's total cost each customer class is responsible and the rate schedules for each class.
2. **Transmission rate cases at the Federal Energy Regulatory Commission (FERC):** The CPUC is required to allow recovery of all FERC-authorized costs. Because transmission rates are subject to oversight by FERC, the transmission revenue requirements of the various utilities that participate in the CAISO are determined in FERC proceedings, called Transmission Owner (TO) rate cases.
3. **Energy Resource Recovery Account (ERRA) proceedings**: The CPUC annually reviews each utility's fuel and power purchase forecast and, to the extent deemed reasonable, passes through those costs without any profit or mark-up for the utility. Some public purpose charges are also authorized here.
4. **Program Budget allocations**: Specific program area proceedings in which program budgets are determined.

The utilities earn a rate of return (authorized profit from rate base) on utility-owned and capitalized assets and equipment. For many cost categories, such as purchased power and fuel, there is no rate of return or profit – the utilities are only reimbursed for these costs from customers as "pass-through" costs.

Categorization of Utility Costs

Utility costs or revenue requirements fall into three major categories: generation, distribution, and transmission. While this basic categorization of costs reflects major areas of utility operations or business units, it is also used to determine what portions of utility costs should be paid by different types of customers. For instance, some customers do not receive full service (also known as "bundled service") from the utility and may generate their own electricity on site or buy electricity from a non-utility source (e.g., an Electric Service Provider (ESP), or a Community Choice Aggregator

(CCA)). Customers who receive electricity from a CCA or ESP do not typically pay generation costs but do pay transmission and distribution costs. However, these customers are also required to pay non-bypassable charges for generation procured on their behalf before they departed from bundled service. Additionally, some larger customers receive service at transmission voltage levels and are not charged for use of the utility distribution system. **Table 2.1** offers a breakdown of the major components of the electric IOUs' 2022 revenue requirements.

Table 2.1: 2022 Electric IOU Authorized Revenue Requirements ($000)

Revenue Component	SCE	PG&E	SDG&E
Generation / Energy Procurement	5,124,938	4,109,994	1,138,195
Purchased Power	4,202,928	1,942,247	1,007,365
Utility Owned Generation	195,934	568,532	143,715
General Rate Case	694,344	2,068,041	184,078
Other Regulatory	31,732	(468,826)	(196,963)
Distribution	7,457,937	6,127,361	1,624,992
Transmission	1,390,045	2,948,943	772,822
Public Purpose Programs	1,567,945	862,897	643,144
Bonds and Fees	410,758	574,144	54,300
Total 2022 Revenue Requirement	**15,951,623**	**14,623,338**	**4,233,453**

Rate Base

The rate base is the book value, after depreciation, of the generation, distribution, and transmission infrastructure owned and operated by the utility for the provision of electric service. Utilities earn a regulated Rate of Return (ROR) on rate base based on their capital structure, debt interest rates, and authorized return on equity (ROE). This ROR is the main source of profit for regulated utilities. Other things being equal, a larger rate base results in a higher net profit for the utilities.

Depreciation causes the utilities' rate bases for existing assets to decline over the useful life of the assets, while building new plants or making capital improvements to existing plants causes their rate bases to increase. Changes in rate base also result in changes in the depreciation expense allowance utilities are authorized to collect. As shown in **Figure 2.1** below, the result of these competing effects has historically been a net increase in rate base. **Figure 2.1** indicates that between 2012 and 2022, the utilities' rate bases doubled in size from $41.6 billion to $83.0 billion, or a 100 percent increase in nominal dollars over the past decade, triggering corresponding increases in GRC revenue requirements.[15]

Figure 2.1: Trends in Electric Utility Rate Base

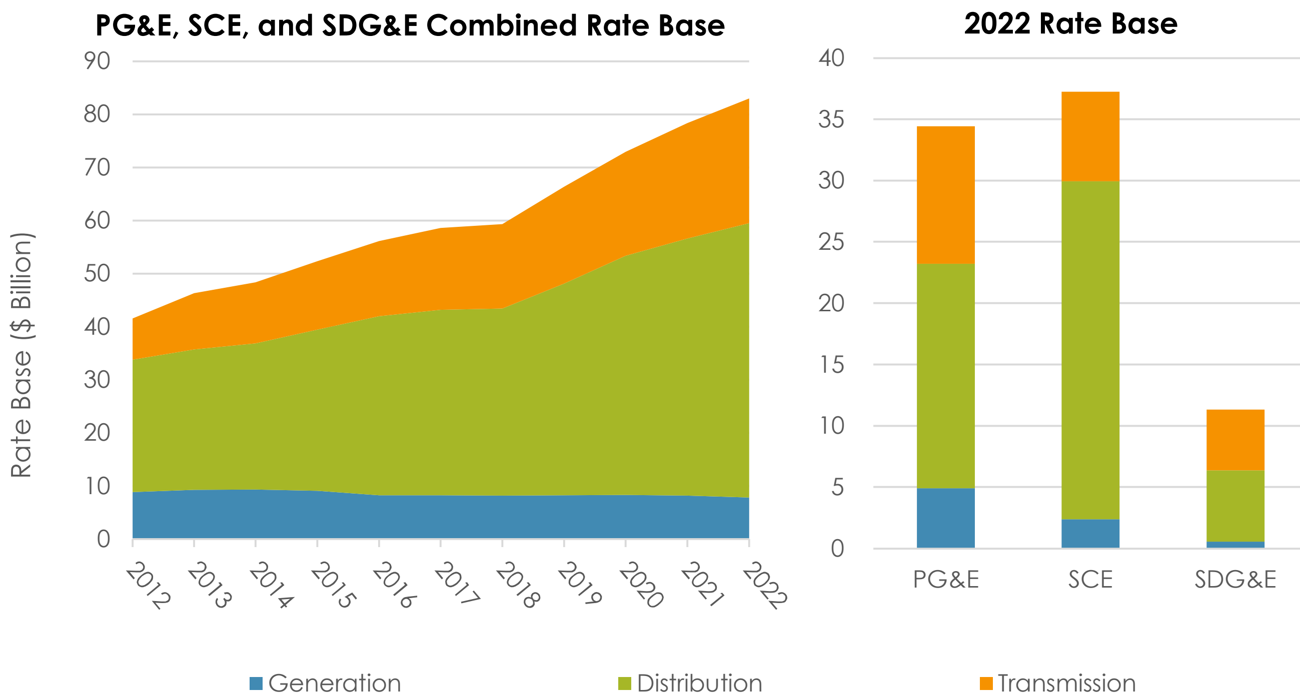


Table 2.2 shows the contributions of generation, transmission, and distribution components to the 2022 rate base.

Table 2.2: 2022 Utility Rate Base Components ($000)

Category	PG&E	SCE	SDG&E	Total
Generation	4,913,190	2,373,167	558,372	
Distribution	18,292,430	27,576,739	5,799,514	
Transmission	11,227,463	7,298,750	4,966,317	
Total All IOUs	**34,433,083**	**37,248,656**	**11,324,202**	**83,005,942**

15 When adjusted for inflation, the 2012 rate base equals $51.6 billion. Therefore, an inflation-adjusted comparison of rate base from 2012 to 2022 indicates the rate base increased in size from $51.6 billion (adjusted for inflation from $41.6 billion) to $83.0 billion, or 61 percent.

III. General Rate Case Revenue Requirements

Costs that utilities can forecast with reasonable accuracy are examined and approved by the CPUC in general rate case (GRC) proceedings. In January 2020, the major utilities were directed by the CPUC to take procedural steps to transition from a three-year GRC cycle to a four-year GRC cycle.[16] In these GRC proceedings, the CPUC sets a pre-specified revenue requirement for the first year in the cycle, or "test year," with formulaic adjustments for the subsequent "attrition years" until the next GRC cycle commences.

The utilities' authorized revenue requirements typically remain unchanged even if the utilities spend more or less than authorized by the CPUC. The exception to this occurs in operations covered by balancing and/or memorandum accounts which can adjust the authorized revenue requirement based on actual spending upon CPUC approval.

Approximately 67 percent of the utilities' electric revenue requirements are set in GRCs at the CPUC and the FERC (FERC sets the revenue requirement for transmission assets), while the remaining 33 percent consists of pass-through of the costs of power procurement, DWR bond charges, nuclear decommissioning trusts, Public Purpose Programs, fees, and regulatory expenses approved by the CPUC.

GRC revenue requirements generally break down into the Distribution, Utility Owned Generation (UOG), and Transmission categories, and each is comprised of the following major cost elements: O&M, Depreciation, Return on Rate Base, and Taxes. **Table 3.1** below summarizes the total CPUC-jurisdictional GRC revenue requirements as broken down into these cost categories for the three electric utilities, followed by detailed descriptions of each.

[16] The CPUC adopted a revised general rate case filing schedule to be applied to all future GRC applications, effective June 30, 2020. Because the utilities were in various stages of their current GRCs, they were directed to take procedural steps to implement the transition to the four-year GRC cycle. Source: CPUC Decision 20-01-002, January 22, 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF.

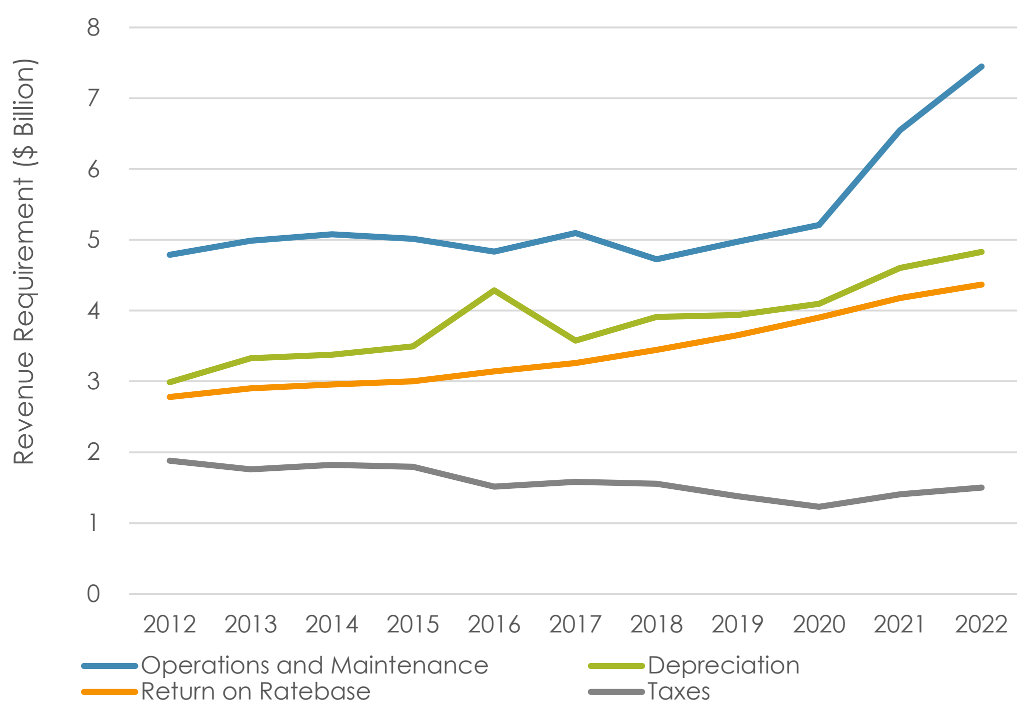
Table 3.1: 2022 General Rate Case Revenue Requirements ($000)[17]

	PG&E	SCE	SDG&E
Operation and Maintenance	3,500,328	3,103,271	848,160
Depreciation	2,400,960	2,011,669	420,323
Return on Rate Base	1,722,508	2,293,306	355,390
Taxes	571,605	744,034	185,198
Total	**8,195,402**	**8,152,281**	**1,809,071**

(Excludes FERC-determined transmission revenue requirements)

Figure 3.1 below shows a ten-year trend of the costs for O&M, Depreciation, Return on Rate Base, and Taxes for the utilities.

Figure 3.1: Trends in General Rate Case Revenue Requirement[18]



- **<u>Operations and Maintenance (O&M)</u>:** These costs include all labor and non-labor expenses for a utility's operation and maintenance of its generation plants and distribution system. While the utilities are required to maintain their systems in accordance with safety and reliability standards and industry best practices, the CPUC does not typically dictate how the utilities spend O&M funds. Depending on how the utilities manage various projects, they may spend more or less than the CPUC authorized O&M budget.

[17] Amounts shown include revenues adopted by the CPUC in the utilities' GRCs and additional revenues approved by the CPUC for inclusion in base revenues after the GRC decisions were issued.

[18] Values shown are for Distribution and Generation Revenue Requirement.

To better assess utility spending on ensuring the safe operation of their systems, the CPUC adopted a framework for incorporating risk-based decision-making into GRCs in 2014. This risk-based decision-making framework involves two key components: the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, and a Risk Assessment Mitigation Phase (RAMP) for each large energy utility one year in advance of its GRC proceeding.

In 2015, the S-MAP applications of the major electric and gas utilities were consolidated, and the utilities and parties discussed the methods by which to assess the risks in their operations. In 2020, a second S-MAP was opened to enhance the RAMP process. Each utility's RAMP proceeding utilizes the reporting format developed in the S-MAP proceeding and describes how the utility plans to assess and mitigate its risks. SDG&E and SoCalGas were the first utilities to initiate the RAMP, in October 2016, followed by PG&E in November 2017, and SCE in November 2018. After the initial RAMP filings, RAMPs have preceded each GRC filing thereafter. For example, in June 2020, PG&E submitted its 2020 RAMP. SDG&E and SoCalGas submitted a succeeding RAMP in May 2021. In the general rate cases, the CPUC undertakes a thorough review of O&M costs, separately, for generation and distribution related facilities, and for general plant. Beginning in Test Year 2019, the CPUC incorporated RAMP findings into the utilities' GRC decisions.

- **Depreciation:** Capital investments in facilities and assets are initially financed by the utilities' own funding sources and are returned to the utilities with ratepayer funding in the form of a depreciation allowance. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.

- **Rate of Return on Rate Base:** Because the utilities provide the upfront financing for all capitalized expenditures, they are entitled to a rate of return (ROR) on the invested capital. The ROR is the weighted average cost of debt and shareholder equity, and they have the opportunity to earn a fair and reasonable return sufficient to allow the utilities to obtain financing. Formerly determined in each utility's GRC, the CPUC now determines the ROR in a separate cost of capital proceeding for the major IOUs. The utilities' actual ROR may be more, or less, than what is authorized by the CPUC, depending on how well the utilities manage their operations and costs. In most instances, if the utilities keep costs below their authorized revenues, actual ROR will exceed the authorized level. GRC ratemaking is aimed at providing the utilities with an incentive to stay within approved, pre-specified budgets. Under this ratemaking treatment, utility profits decline if spending is higher than the GRC authorized revenue requirement, and vice versa.

The utilities do not earn a return on purchased power and fuel expenditures, which, as noted elsewhere in this report, are pass-through costs reviewed in Energy Resource Recovery Account (ERRA) proceedings.

The CPUC also requires the utility to track some costs in "one-way balancing accounts." For expense categories tracked in one-way balancing accounts, if the utility underspends, then the utility returns the funds to ratepayers. If a utility overspends, in a one-way balancing account, the utility has to absorb the costs in profits. One-way balancing accounts are often used for mandated programs to earmark funds for a specific purpose. For activities where there is great uncertainty in cost forecasts, but for which the CPUC wants to encourage the utility to spend in order to meet its obligations (e.g. to procure enough gas to meet its bundled core gas procurement obligations, or to perform safety/reliability work to meet safety obligations), the CPUC often grants two-way balancing accounts which enable the utility to recover reasonable costs that exceed the target dollar amount.

Distribution Revenue Requirement

Since 2012, the total distribution revenue requirement has increased, from $9.06 billion to $15.2 billion (**Figure 3.2**).[19] Over the same time period, depreciation expenses have experienced the greatest increase, with an approximate 2.5 percent average annual growth rate.[20] The increases in distribution costs are primarily due to capital additions and ongoing infrastructure modernization and improvements to the distribution system for wildfire mitigation, which have increased rate base, as discussed in the Rate Base section. Figure 3.2 also shows a significant increase in O&M. This is largely attributable to the timing and approval of higher wildfire mitigation and vegetation management expenses, and authorized significantly higher wildfire liability insurance coverage. The O&M for 2022 also includes recovery of catastrophic event expenses.

[19] When adjusted for inflation, the 2012 total distribution revenue requirement equals $11.2 billion, which indicates distribution revenue requirement has increased approximately 36 percent from 2012 to 2022 (in 2022 dollars).

[20] Adjusted for inflation.

Figure 3.2: Trends in Distribution Revenue Requirement

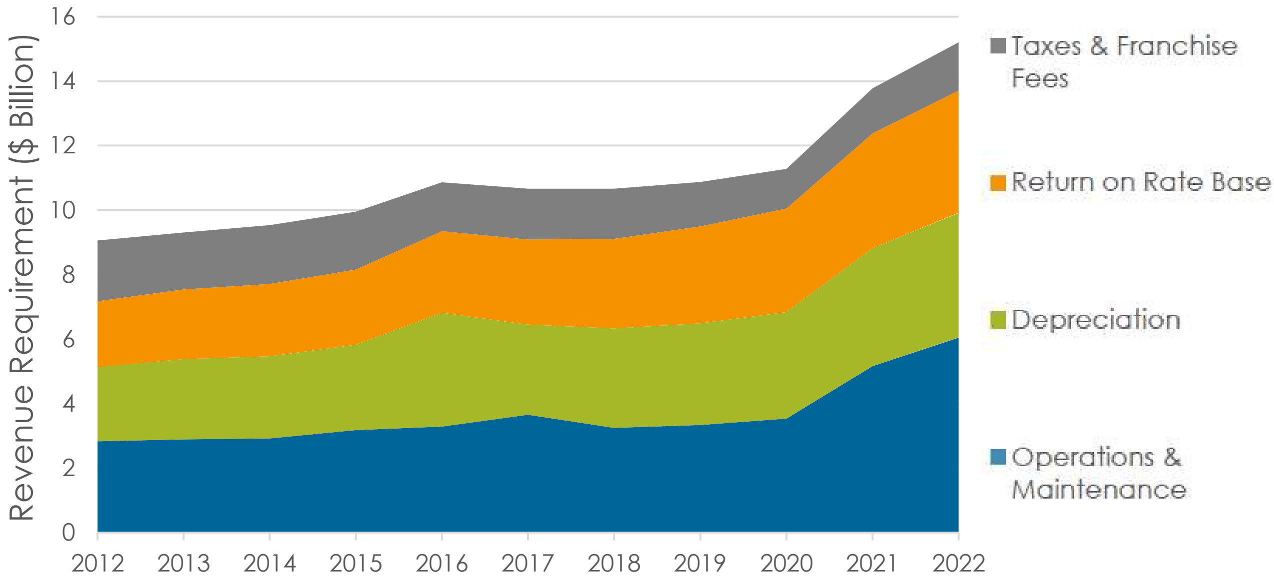


Table 3.2 below shows the contributions of distribution components to the 2022 revenue requirement.

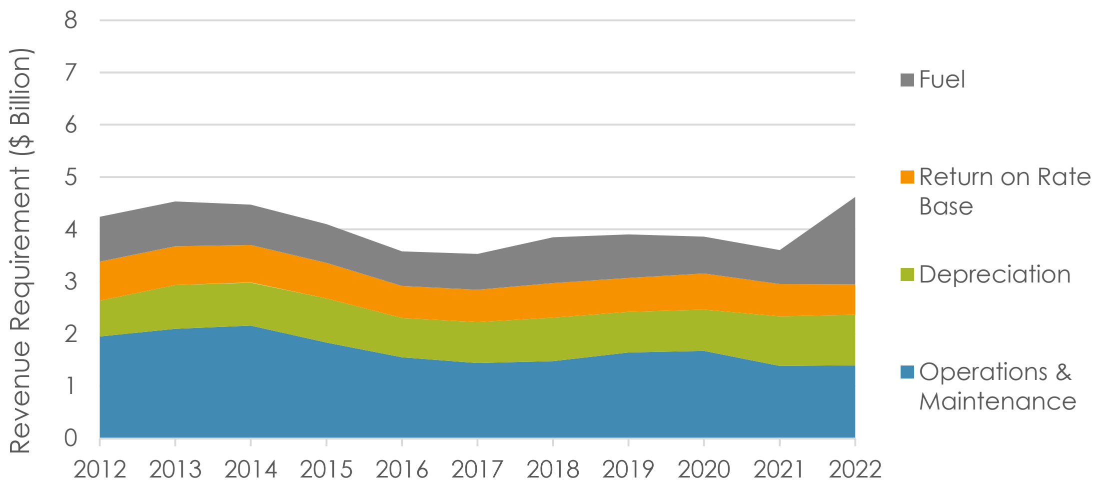
Table 3.2: 2022 Distribution Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	2,502,850	2,791,095	759,737
Depreciation	1,691,406	1,805,135	370,121
Return on Rate Base	1,361,499	2,117,673	309,936
Taxes and Franchise Fees	571,605	744,034	185,198
Total	**6,127,361**	**7,457,937**	**1,624,992**

Utility Owned Generation Revenue Requirements

The revenue requirement for utility-owned (or retained) generation (UOG) includes O&M costs, depreciation, and return on rate base related to these facilities. As older generating plants depreciate, costs of owning those plants decrease over time, even though costs of operating them may increase. As a result, the generation revenue requirement tends to decrease over time as shown in **Figure 3.3**. As new plants are built by the utilities or capital improvements are made to existing facilities, the capital costs of the new plants typically exceed the capital costs of the old plants they replace. In 2022, fuel costs were higher due to market purchases which drove an increase in the generation revenue requirement.

Figure 3.3: Trends in Generation Revenue Requirement



***Fuel costs are not included in the GRC but are reflected in generation revenue requirements.**

Following electric industry restructuring in the late 1990s and the utilities' divestiture of fossil-fueled generation, UOG (including fuel costs) now accounts for only 8 percent of their combined revenue requirements. The 2022 generation revenue requirement for the electric IOUs is shown in **Table 3.3**.

Table 3.3: 2022 Generation Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	997,478	312,176	88,424
Depreciation	709,554	206,534	50,201
Return on Rate Base	361,009	175,633	45,454
Total	**2,068,041**	**694,344**	**184,078**

Figure 3.4 shows the components of the 2022 UOG revenue requirement by sources. PG&E's UOG consists primarily of nuclear power (Diablo Canyon) and several natural gas plants (e.g., the 660-megawatt (MW) Colusa Generation Station, 580 MW Gateway Generating Station, and 163 MW Humboldt Bay Generating Station). SCE's UOG

portfolio consists primarily of nuclear (Palo Verde Nuclear Generating Station) and natural gas power plants, including the 1,035 MW Mountain View Power Plant and Peaker plants. SDG&E's UOG includes natural gas plants: the 560 MW Palomar Energy Center, the 96 MW Miramar Energy Facility, the 495 MW Desert Star Energy Center, and the 42 MW Cuyamaca Peak Energy Plant.[21]

Figure 3.4: 2022 Revenue Requirements of UOG Sources

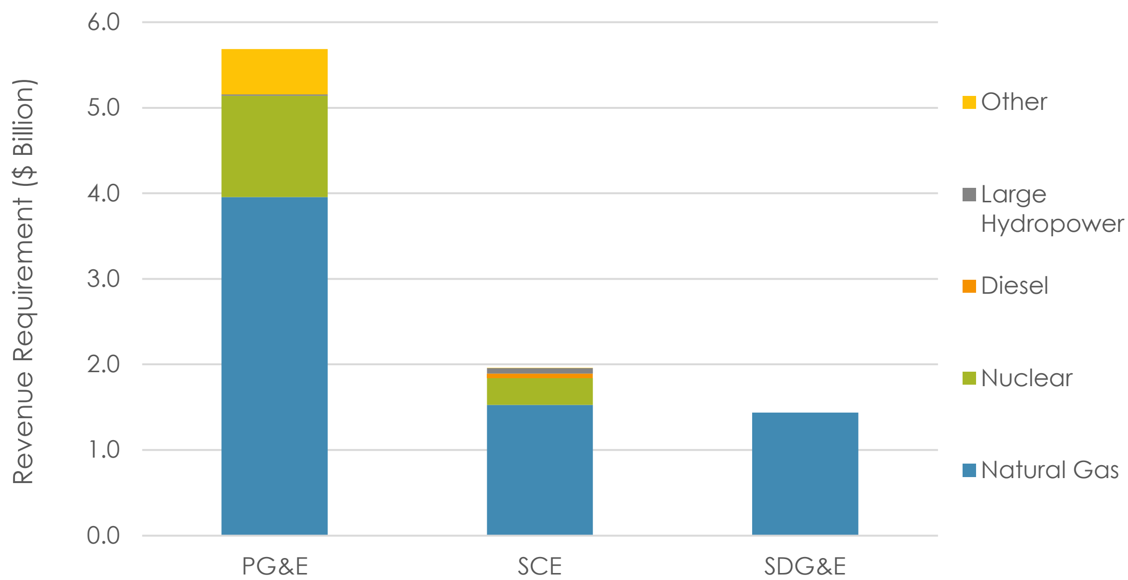


Table 3.4: 2022 UOG Sources Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Natural Gas	395,539	152,510	143,715
Diesel	0	5,459	0
Nuclear	118,309	31,312	0
Other	52,893	258	0
Large Hydropower	1,790	6,395	0
Total	**568,532**	**195,934**	**143,715**

[21] Desert Star Energy Center was purchased from Sempra Natural Gas in October 2011 and Cuyamaca Peak Energy Plant was purchased in January 2012.

Nuclear Revenue Requirement

SCE and SDG&E hold joint ownership in San Onofre Nuclear Generating Station (SONGS) and SCE holds partial ownership in the Palo Verde Nuclear Generating Station (operated by Arizona Public Service).[22] Due to operating issues at SONGS, this facility was taken offline in the first quarter of 2012 and permanently shut down in June 2013. In 2014, SCE and SDG&E were authorized by the CPUC to purchase replacement power to alleviate the capacity shortfall. Ratepayer and SCE/SDG&E shareholder responsibilities for SONGS-related costs were determined in a 2014 decision in the SONGS Investigation, which was subsequently re-opened to determine whether that decision represented a fair and equitable balance between ratepayer and shareholder recovery. A final decision on SONGS related costs was issued in August 2018 (D.18-07-037).

PG&E owns and operates the Diablo Canyon Nuclear Power Plant. In January 2018, the CPUC approved a joint request by PG&E and other parties to shutter the plant's two generating units in 2024 and 2025 (D.18-01-022) and approved ratepayer funding of $241.2 million for employee retention and retraining ($222.6 million) and license renewal activities ($18.6 million). In September 2018, SB 1090 authorized an additional $225.8 million in funding for the shutdown of Diablo Canyon Nuclear Power Plant, with $140.8 million of that amount for employee retention programs and $85 million for a Community Impact Mitigation Program (see also D.18-11-024). While the passage of SB 846 on September 2, 2022, reversed the CPUC's order in D.18-01-022 to close Diablo Canyon in 2024/25, it retained the previously approved funding[23]. In total, $467 million in ratepayer funding was approved. Diablo Canyon's forecast 2022 Operating Costs (i.e., O&M) were $325 million while its forecast 2022 capital expenditures were $13 million (see A.21-06-021 testimony).

SCE owns a 15.8 percent share of the Palo Verde Nuclear Generating Station located near Phoenix, Arizona. Arizona Public Service Company (APS) operates Palo Verde while SCE compensates APS for its 15.8 percent share of expenses. SCE also oversees and reviews Palo Verde operations through participation in two committees. SCE's 15.8 percent share of Palo Verde's 2022 operating costs (O&M) was approximately $73 million while its share of 2022 capital expenditures totaled approximately $36 million (see D.21-08-036).

The Nuclear Decommissioning Cost Triennial Proceedings (NDCTP) provide a venue for the utilities to forecast their expected decommissioning costs and for the reasonableness review of recorded costs at their respective nuclear facilities. In D.21-09-003, the Commission approved PG&E's 2018 NDCTP, authorizing a settlement

[22] In addition to the list of UOG resources above, SCE also owns and operates a diesel generating facility on Santa Catalina Island. Since the island's load is not connected to the grid, the supply and demand are not included in the forecasts, but the expense is included in the revenue requirements.

[23] The CPUC reversed the order to close Diablo Canyon by 2024/25 in accordance with SB 846 in D.22-12-005 on December 1, 2022.

agreement allowing PG&E to collect $112.5 million in annual revenue requirement from 2022 through 2029 to fund the Diablo Canyon decommissioning trusts. In December 2021, the CPUC approved the 2018 NDCTP for SONGS, D.21-12-026, in which SCE and SDG&E requested no rate changes. Neither of the ongoing NDCTP proceedings, A.21-12-007 for PG&E and A.22-02-016 for SCE and SDG&E, have requested rate changes.

Apart from the O&M, depreciation and ROR authorized in GRC proceedings, and fuel costs authorized in ERRA proceedings, nuclear generation also results in additional costs, which are collected as separate revenue requirements:[24]

- Fees for disposal and storage of spent nuclear fuel are required by the U.S. Department of Energy (DOE) for temporary and permanent storage facilities. Costs incurred for storage of spent nuclear fuel are currently reimbursed by DOE through claims for prior years consistent with PG&E's 2014 General Rate Case Settlement for Refunding DOE Litigation and Claims Net Proceeds to Customers. In D.07-03-044 the CPUC established the Department of Energy Litigation Balancing Account (DOELBA) to track litigation costs and proceeds received from DOE for the cost of spent nuclear fuel storage on site. SCE and PG&E have been directed to continue to report updated information regarding the net underlying costs supporting the payments from DOE through the litigation and claims process in each nuclear decommissioning cost triennial proceedings (see D.21-09-003 and D.21-12-026).

- Nuclear decommissioning of generating plants at the end of their operating lives is required by the United States Nuclear Regulatory Commission (NRC). To pay for these eventual decommissioning efforts, the utilities were required to establish Nuclear Decommissioning Trust Funds (NDTF). The funds placed into the NDTF are estimated in nuclear decommissioning cost triennial proceedings. The amounts authorized through the nuclear decommissioning costs are funded through rates during the operating lives of the nuclear plants.

Authorized Rate of Return

Authorized rate of return on rate base (ROR) is the weighted average cost of capital used to finance utility capital expenditures. Cost of capital is the combination of the cost of debt and return on equity (ROE) as weighted according to the IOU's capital structure, all of which are adopted in separate Cost of Capital proceedings held every three years. The financing of IOU capital expenditures, or rate base, is included in adopted revenue requirements as part of the cost of service.

Figure 3.5 illustrates the CPUC authorized ROR since 2012 for major energy utilities. The figure does not include ROR authorized by FERC for IOU transmission systems; it includes only the

[24] Nuclear Decommissioning and DOE Decommissioning & Disposal expenses are categorized with Bonds & Fees because they are collected separately.

ROR authorized by the CPUC for UOG and distribution. **Figure 3.6** shows trends in the CPUC authorized ROE component of ROR since 2012.

Figure 3.5: Trends in Weighted Average Rate of Return (ROR)

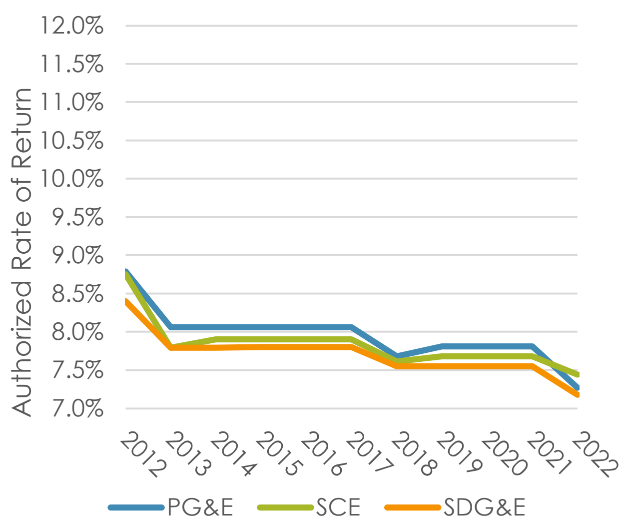


Figure 3.6: Trends in Return on Equity (ROE)

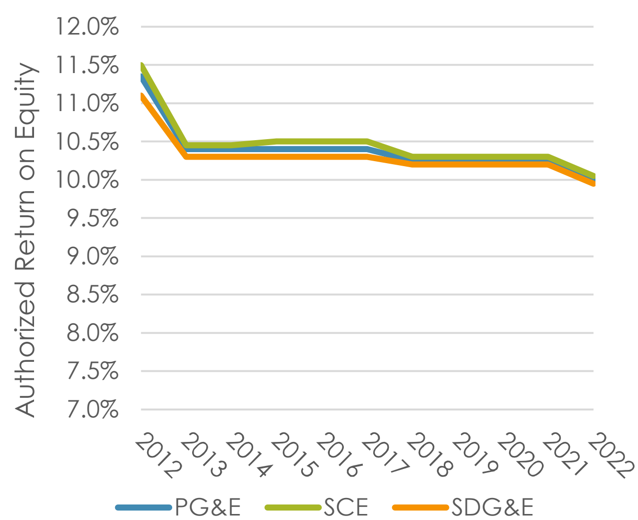
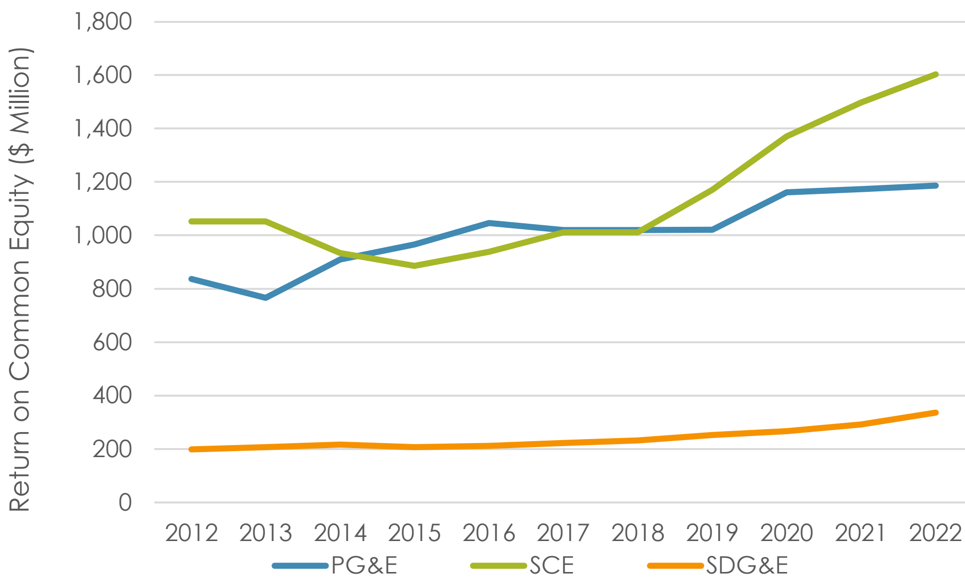


Figure 3.7 shows trends in dollars authorized for return on common equity for major energy utilities since 2012. The figure does not include return on common equity authorized by FERC for IOU transmission systems; it includes only the return on common equity authorized by the CPUC for UOG and distribution.

Figure 3.7: Dollar Trends in Authorized Return on Common Equity



The major energy utilities are currently required to file a cost of capital application every three years, although this review cycle can be, and has sometimes been, extended. In D.22-12-031, the CPUC established the Test Year 2023 cost of capital and authorized the previously authorized cost of capital mechanism through the 2023 test year cycle for SCE, PG&E, and SDG&E, and SoCalGas.

Transmission Revenue Requirement

Background and Jurisdictional History

As part of energy restructuring, the CAISO was created by the legislature and given operational control[25] over the utilities' high voltage transmission lines on March 31, 1998, and authority for determining transmission revenue requirements was transferred to FERC.[26] The transmission revenue requirements (TRR) authorized by FERC include the same core components (e.g., cost-of-service, depreciation, cost of capital, and taxes) as the general rate cases at the CPUC.

Components of the electric grid are considered part of the interstate transmission system and under FERC jurisdiction if they are at a higher voltage and meet FERC criteria for connectivity in the transmission system. Each utility defines its transmission voltage differently. PG&E, SCE, and SDG&E consider all power lines at and above 60

[25] The Restructuring Decision (1996) functionally created the implementation of the CAISO through the acceptance of AB 1890 (Sept. 24, 1996).

[26] FERC Order 888 and 889 (April 1996) required utilities to open transmission grids for access by all generators on a nondiscriminatory basis and functionally unbundled rates for generation, transmission, and ancillary services. The CPUC acceded to this regulatory transfer in its Electric Restructuring Decision D.95-12-063 (Dec. 20, 1995).

kV, 200 kV, and 69 kV, respectively, as transmission-level voltage, and if they meet the configuration requirements to make them part of the interstate transmission system, these transmission assets fall under CAISO's operational control and are regulated by FERC.[27] All other electric power lines and assets remain under CPUC regulatory control and jurisdiction.

The three major IOUs file Transmission Owner (TO) formula rate cases at FERC, establishing rates of depreciation, cost of capital, and other elements of their ratemaking framework that typically remain in effect for several years. A formula provides the structure through which forecasted expenses and capital costs can be recovered, as well as the opportunity for annual true-ups to account for over- or under-collection in a previous year's rates. Further, a formula prevents the need for an entirely new rate case at FERC every year.

Transmission Revenue Requirements and Trends

The CPUC is the statutorily designated agency representing the interests of California retail ratepayers at FERC[28], advocating for just and reasonable rates for California consumers in TO rate cases. Due to the importance and complexity of these rate cases, CPUC Legal Division and Energy Division staff analyze a multitude of expenses and capital projects for cost effectiveness, reliability, safety, and overall prudence of expenditures. Specific transmission revenue requirement (TRR) components examined include return on equity, capital structure, taxes, depreciation, cost-of-service, and the forecast of expenses of transmission capital projects. This advocacy is essential, as FERC affords the utilities a presumption of prudence for all costs included in a TO rate case. Therefore, it is incumbent on the CPUC and other intervenors to do our best to ensure the rates that FERC approves are just and reasonable.

When a transmission owner files a new rate case at FERC, the CPUC and other intervening parties analyze the filing and typically protest components that appear to be unjust and unreasonable for ratepayers. At that point, FERC usually sets the case for hearing and facilitates a settlement process. The CPUC and others then conduct discovery on the utility's filing to collect further information and develop fact-based recommendations on what we believe is a just and reasonable revenue requirement to protect ratepayers. While the parties typically reach a settlement on the final TRR, there are instances where some components of a rate case, or the entire case, require litigation.

As explained in last year's Report, in October 2020, FERC issued a final order on most of the issues in PG&E's TO18 transmission owner rate case, which was litigated for 2017 rates at FERC. FERC followed with an order on the remaining return on equity ("ROE")

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[27] Please note that much of SCE's 115 kV assets, while at transmission voltage are configured in such a way that they are not considered part of the interstate transmission system. Therefore, these assets are considered "sub-transmission" and remain under the CPUC's jurisdiction.

[28] CPUC Code, Section 307(b).

issue in TO18 in March 2022. With interest, the total TO18 refunds to ratepayers will exceed $300 million. However, because FERC has yet to issue an order on PG&E's compliance filing in TO18, the refunds are being withheld from ratepayers as of the publication of this Report. The impact of this delay is compounded, as the settled outcome of TO19, which is expected to yield additional refunds approaching $400 million for ratepayers for 2018 rates, is tied to a final non-appealable decision in TO18.

In October 2018, PG&E filed its Twentieth Transmission Owner Formula Rate Case (TO20) at FERC. Settlement of all issues was accepted by FERC on December 30, 2020, with the term of the formula rate effective through 2023. In addition to reaching settlement on the TRR, the CPUC had success negotiating the establishment of the Stakeholder Transmission Asset Review (STAR) Process. As over 80 percent of PG&E's capital projects (i.e., over $1 billion annually) receive no formal review by the CAISO or CPUC, the STAR Process provides stakeholders with the opportunity to review substantial data on future projects, participate in stakeholder meetings, and seek additional information to understand, and provide input on, PG&E's capital spending. PG&E's Total TRR in 2022 was $2.95 billion, over $900 million more than the total revenue requirement in 2021 (i.e., $2.04 billion). The 2022 TRR in the TO rate case was $660 million higher due in part to significantly greater spend on O&M expenses, including wildfire-related vegetation management, as well as other upgrades for grid operations to support external projects on Work at the Request of Others (WRO). Another contributing factor was the inclusion of over $300 million in costs related to under-collection at the CAISO for others' use of the PG&E transmission grid in the Transmission Access Charge Balancing Account Adjustment for 2022.

In SCE's most recent rate case, parties reached a settlement agreement on July 1, 2020, and FERC approved the settlement on September 23, 2020. The settlement required annual Informational Filings to correct any under- or over-collection of approved expenses from the previous year. For 2022, SCE's increase in TRR was principally attributed to: 1) an increase in A&G expenses tied to an upward adjustment to the 2017/2018 wildfire reserve, 2) a net increase of FERC-jurisdictional rate base and incentive construction work in progress plant balances (partially offset by decreases in Accumulated Depreciation items), and 3) a large under-collection from the 2020 rate year. A one-time cost adjustment (reduction) also played a role.

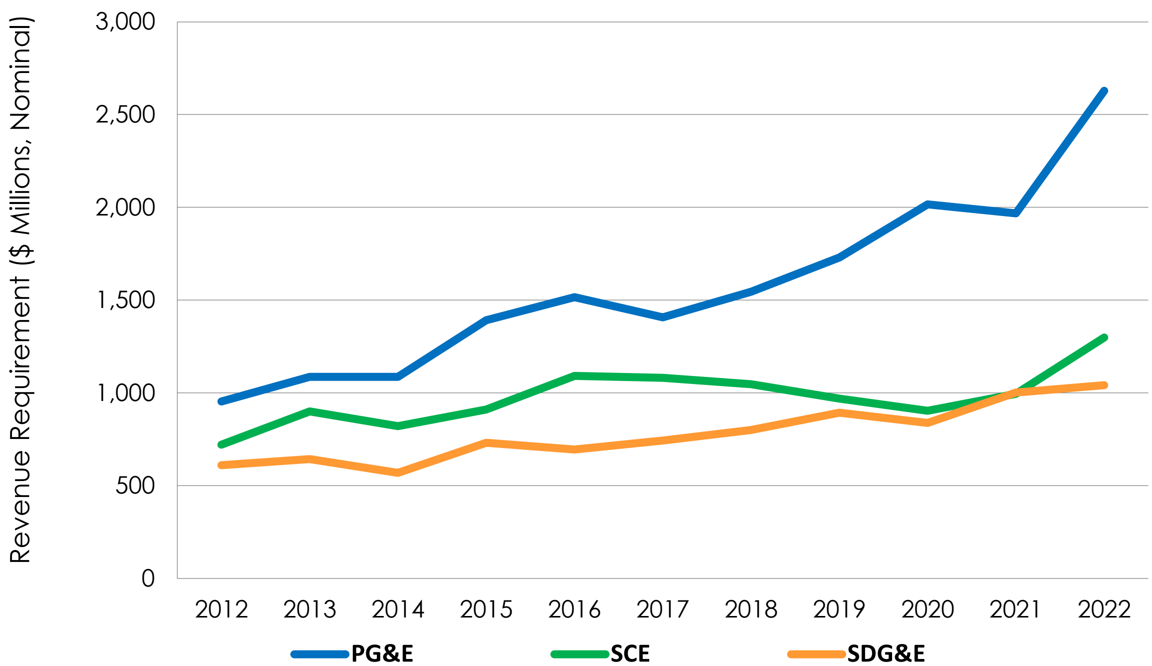
Further, as part of the FERC settlement, SCE committed to establish and maintain a Stakeholder Review Process (SRP) for review of SCE's Five-Year Transmission Investment Plan for transmission projects and costs. SCE submitted its fifth semi-annual SRP data set to stakeholders for review on December 1, 2022.

SDG&E filed its fifth (TO5) formula rate application on October 30, 2018. Parties successfully negotiated an uncontested settlement approved by FERC on January 24, 2020. For the duration of the formula rate, SDG&E will file Annual Updates with FERC to set rates for the coming year, reconcile differences between forecast and actual expenditures, and other factors affecting their transmission revenue requirement. For 2022, SDG&E's 5 percent increase in TRR can be attributed to:1) higher O&M expenses, especially maintenance costs of overhead and underground lines; depreciation expenses; and property and payroll taxes and 2) an increase in the transmission rate base of approximately $260 million, or 6 percent.

The estimated savings from the CPUC's advocacy in FERC TO rate cases bring the cumulative savings from 2008 to 2022 to approximately $3.6 billion for California ratepayers.

Even with the savings for ratepayers secured by the CPUC's efforts, transmission revenue requirements for the IOUs have been trending upward since 2012, increasing at an average annual growth rate of 10.7 percent for PG&E; 6.1 percent for SCE; and 5.5 percent for SDG&E as shown in **Figure 3.8**.

Figure 3.8: Trends in TO Rate Case Transmission Revenue Requirement[29]



Historically, much of the increase in the utilities' revenue requirements has been due to transmission infrastructure capital investments. Years ago, large additions to utilities' rate base included CAISO-approved reliability projects and those needed for meeting Renewables Portfolio Standard (RPS) mandates. These projects expand capacity of the grid, enabling interconnection of new electric generation to the grid, as well as compliance with North American Electric Reliability Corporation (NERC) requirements.

[29] Does not include cost adjustments related to FERC balancing accounts.

The current trend in transmission capital investment shows that all three electric utilities continue to increase their spending on "self-approved" transmission projects. "Self-approved" means there is no existing requirement that these projects undergo review for cost or need by CAISO, CPUC, or any other third party. The three electric utilities report that from 2012 to 2021, these self-approved transmission projects accounted for 43.5 percent ($10.0 billion) of their collective transmission investment. However, in just the last three years for which the CPUC has actual data (i.e., 2019 to 2021), 63 percent ($4.2 billion) of the electric utilities' investments were on self-approved projects, as shown in **Table 3.5**. More recently, large expenses such as Administrative and General costs, Operation and Maintenance expenses, swings in balancing accounts, and one-time cost adjustments charges, as mentioned above, are also playing prominent roles.

Table 3.5: 2021 Self-Approved Transmission Projects as a Share of Transmission Capital Investment

	2012-2021 ($M)	2019-2021 ($M)
Total IOU Transmission Capital Projects	22,949	6,605
Self-Approved Capital Projects	9,978	4,181
Percentage of Self-Approved Projects	43.5%	63.3%

While FERC has found that these self-approved projects do not fall under the planning requirements of existing FERC regulations, the CPUC and other stakeholders had success in 2020 negotiating PG&E's Stakeholder Transmission Asset Review (STAR) Process and SCE's Stakeholder Review Process (SRP) as parts of their respective TO rate cases at FERC. These stakeholder processes improve transparency of the two utilities' transmission capital projects planned for the next five years. While these stakeholder processes are important steps to help ensure that the IOUs are building the right projects in the right locations at the right times for safety and reliability of the modernizing grid, they occur downstream from transmission planning and are scheduled to expire at the end of 2023. Energy Division's FERC Cost Recovery Section has been playing a significant role in FERC rulemakings, technical conferences, and advising CPUC Commissioners in their roles on FERC's Joint Federal-State Task Force on Electric Transmission, with any eye on ensuring that the substantial buildout of the transmission system in years to come is done so in the most efficient and cost-effective manner.

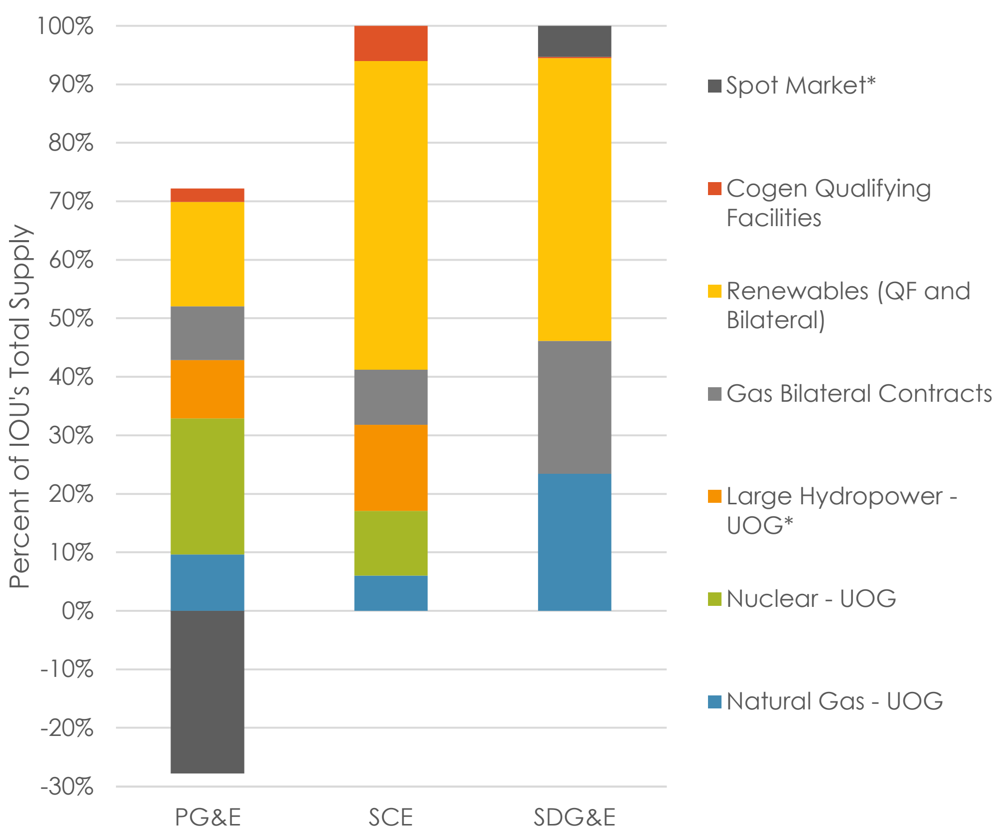
IV. Power Procurement Costs

The generation revenue requirement includes utility owned (or retained) generation (UOG) costs, as well as purchased energy and capacity costs. As previously noted, in the late 1990s the utilities divested almost all of their fossil-fueled generating plants during restructuring, and, as a result, they largely rely on purchased power for incremental electricity needs.

In 2022, purchased power accounted for approximately 62 percent of the total generation revenue requirement, while UOG comprised about 16 percent (see **Figure 4.1**). Power purchase costs represented the largest component of forecasted generation costs and accounted for 18 percent of total revenue requirements. Recovery of these pass-through costs is authorized through the ERRA proceedings. The sale of purchased power is expensed, not capitalized.

PG&E's negative spot market value is due to the formation of several CCAs that left PG&E with excess energy to serve bundled load, which PG&E sold in 2021 spot markets.

Figure 4.1: 2022 Forecast Energy Supply for Electric Utilities



*Includes Other

Background

Heavy reliance on power purchases rather than UOG began with the enactment of AB 1890 in 1996, which restructured the electric utility industry in California and created the CAISO and the Power Exchange. To create a competitive electricity market in which non-utility suppliers would compete with the utilities in the wholesale generation market, the utilities were encouraged to divest at least 50 percent of their fossil-fueled generation. The CPUC provided a rate of return (ROR) incentive to the utilities to encourage them to divest. As a result, the utilities sold a substantial portion of their fossil-fueled generation.

During the 2000-01 energy crisis, the utilities were exposed to high market prices for electricity, due in large part to the divestiture of their generating plants. Authorized utility rates, which were frozen at pre-restructuring levels from June 1996, were no longer sufficient for the utilities to cover the high costs of purchased power; PG&E filed for bankruptcy and both SCE and SDG&E faced substantial financial uncertainty. In response, the Legislature enacted AB 1X, which authorized the DWR to enter into power purchase contracts to stabilize the severely disrupted energy markets.

In 2002, the Legislature enacted AB 57 to return energy procurement responsibilities to the utilities. The legislation required the CPUC to adopt a Long-Term Procurement Plan to ensure sufficient resource availability over time. The legislation also established guidelines for procurement solicitations, cost recovery of power purchases, and integration of renewable resources using long-term planning. The contracts resulting from these solicitations are reviewed by Procurement Review Groups[30] that the CPUC required the IOUs to create.

AB 380 (2005) further addressed CPUC responsibilities for resource planning, requiring the CPUC, in consultation with the CAISO, to establish resource adequacy requirements to ensure that adequate physical generating capacity would be available to meet peak demand. Consequently, the utilities (and all load-serving entities) are required to maintain a 15-17 percent planning reserve margin for generating capacity to ensure they have sufficient capacity available or under contract to serve their forecasted load.

In addition, SB 1078 (2002) established the RPS and required the utilities to serve 20 percent of their electricity demand with renewable resources by 2017. The statute also required each IOU to hold an annual solicitation to procure renewable power. SB 107 (2006) later increased the RPS obligation to 20 percent by 2010 and was

[30] A Commission authorized forum that reviews procurement activities including contracts and reasonableness criteria and offers assessments and recommendations to each utility. The Commission initially established Procurement Review Groups (PRG) in D.02-08-071 as an advisory group to assess the investor-owned utilities' procurement strategy and processes, as well as specific proposed procurement contracts. The PRG includes non-market participants, as well as Energy Division and Cal Advocates.

updated by SB 2 (2011) when the RPS obligation was raised to 33 percent by 2020. SB 350 (2015) raised the RPS obligation to 50 percent by 2030. In 2018, SB 100 set the current RPS obligation to 60 percent by 2030 and the planning goal of obtaining 100 percent of electric retail sales to end-use customers from renewable energy and zero-carbon resources by 2045.

Types of Purchased Power

Department of Water Resources (DWR) Contracts

The California Department of Water Resources (DWR) entered into long-term contracts on behalf of IOU customers during the energy crisis. Each year, DWR had submitted its revenue requirement to the CPUC for adoption and subsequent collection from, or refund to, ratepayers through the DWR Power Charge. Due to the recent expiration of these contracts, DWR's Power Charge revenue requirement for all three utilities was zero. Proceeds from litigation related to these contracts is possible in the coming years and will result in future refunds to customers if realized.

Qualifying Facilities (QFs)

Qualifying Facilities (QFs) are co-generation and renewable generation facilities that qualify to sell power to the utilities under the Federal Public Utility Regulatory Policies Act (PURPA). These facilities must meet FERC's requirements for ownership, size, and efficiency to qualify as QFs. PURPA requires IOUs to interconnect with, and purchase power from, QFs at rates that reflect costs the utility avoids by buying QF power instead of procuring power from other sources. In 2011, the CPUC approved the QF/Combined Heat and Power (CHP) Program Settlement which suspends the "must-take" obligation for QFs over 20 MW and establishes new energy prices for QFs.[31] In 2015, the CPUC added an Emissions Reduction Target associated with CHP procurement of 2.72 million metric tons of greenhouse gas (GHG) Emissions Reductions by 2020.[32] The Settlement ended in 2020, with SDG&E required to do an additional CHP solicitation in 2022 to meet its obligations under the Settlement.[33] In 2020, the CPUC adopted a new Standard Offer Contract (SOC) for QFs, including new avoided cost energy and capacity prices established either at time of contract execution or at time of product delivery.[34] In 2022, the CPUC modified the SOC to allow for storage-paired QFs.[35]

[31] QF costs include Competition Transition Charges (CTC). For a breakout, see table in Appendix A.
[32] CPUC D. 15-06-028, issued on June 15, 2015.
[33] CPUC Resolution E-5163, issued on August 20, 2021.
[34] CPUC D. 20-05-006, issued on May 15, 2020.
[35] CPUC D.22-06-003, issued on June 10, 2022.

Figure 4.2 and **Figure 4.3** break out QF supply and revenue requirements for cogeneration and renewable energy. Since 2005, the total energy supply provided by all QFs has decreased, and the QF revenue requirement has decreased by approximately $1.2 billion. Over the same time period, the revenue requirement for cogeneration QFs has decreased as older contracts expire, and the revenue requirement for renewable QFs has increased.

Figure 4.2: Trends in Purchased Power Supply (GWh)

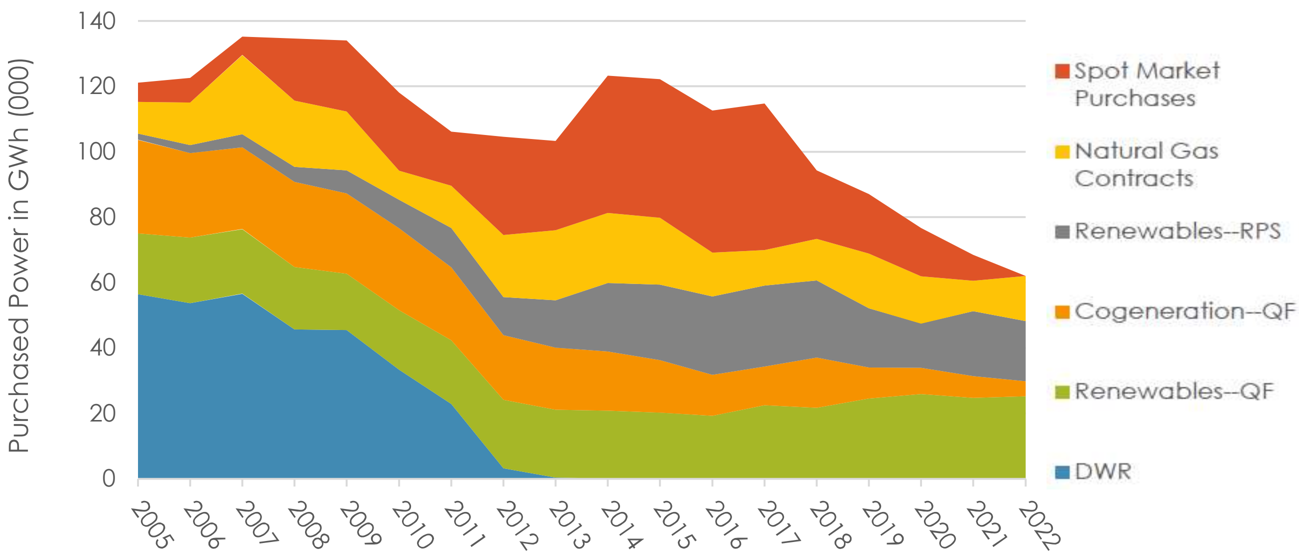
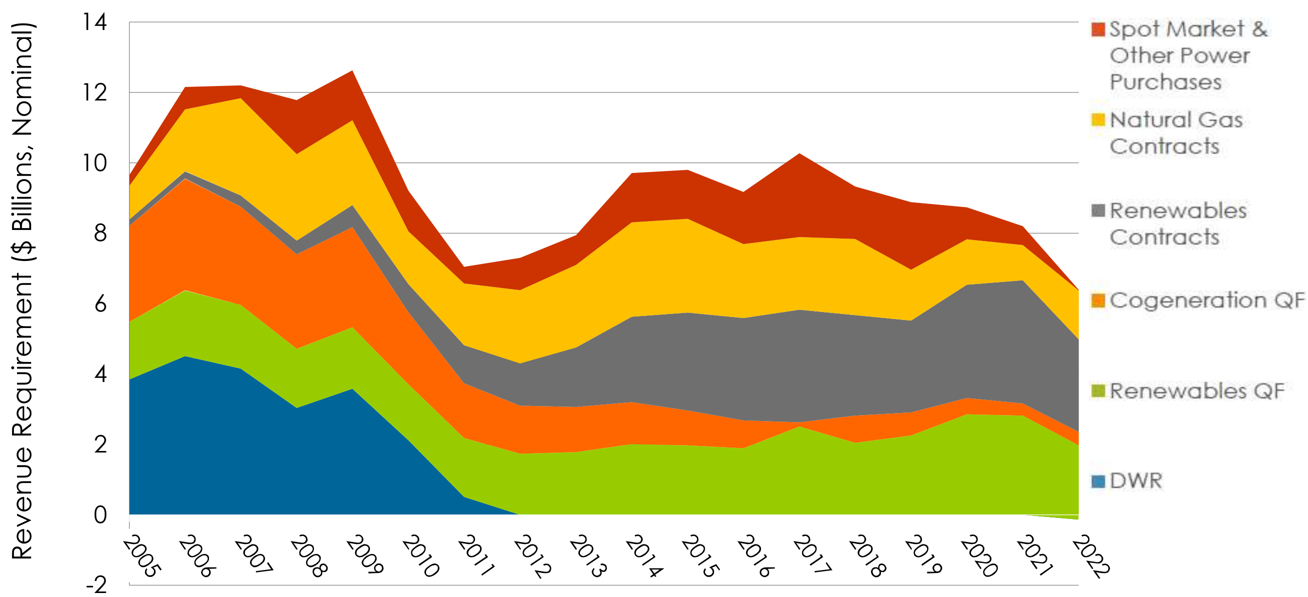


Figure 4.3: Trends in Purchased Power Revenue Requirement



Bilateral Natural Gas Contracts

Bilateral contracts are contracts entered into directly between a utility and an independent power supplier –either a generator or trader-- and are generally sourced by the utilities through a Request for Offers (RFO) open solicitation process. Bilateral contracts can include capacity and energy, usually in the form of a tolling arrangement, or they can be capacity only contracts. Capacity contracts pay generators to be available to produce power and ensure that sufficient capacity is available to meet load.

Renewable Energy Procurement

The IOUs are currently on track to meet or exceed their 44 percent by 2025 RPS target requirements through their procurement of renewables generation. The excess procurement of renewable energy results in surplus or "banked" renewable energy credits, or RECs, which the IOUs may choose to apply towards future RPS requirements instead of procuring incremental renewable resources. In addition to banking excess RECs, for the past several years the IOUs have sold small quantities of their excess REC supply and returned the revenue of these sales to ratepayers. After accounting for the sale of excess RECs and voluntary allocations [36], the IOUs forecast having served 45

[36] Decision (D.) 21-05-030 issued on May 24, 2021, ordered the IOUs to offer PCIA-eligible LSEs voluntary allocations of PCIA-eligible resources.

percent of their electricity demand with RPS eligible resources in 2022. The IOUs have forecasted RPS percentages over 45 percent in 2023 and beyond without any voluntary allocations to other load serving entities. The weighted average RPS procurement expenditures for the IOUs has decreased from 11.1 ¢/kWh in 2003 to 10.7 ¢/kWh in 2021, in real dollars. [37]

Other Power Purchases

Additional power purchase and sale mechanisms exist to ensure that the utilities secure sufficient capacity to balance load across the grid and meet peak load requirements at least cost.

- **Spot Market Purchases:** This term refers broadly to power that the utilities buy from the CAISO's Day-Ahead market to balance the system on a day to day basis. IOUs use the spot market to balance their forecasted load requirements for the following day through transactions that may occur in the CAISO market.
- **Net Long Sales:** These are sales that the utilities make when their expected supply exceeds their forecasted load and may occur in the spot market or other timeframes. These sales reduce ratepayer costs by generating revenue from excess capacity not likely to be needed.
- **Inter-Utility or Power Exchange Agreements:** Traditionally, regulated utilities enter into seasonal and long-term inter-utility exchange agreements with other regulated utilities and other load-serving entities. Through bilateral negotiations the specific terms are crafted to best fit the resources and needs of both parties. Payment is typically in the form of non-cash exchanges of capacity and energy balanced to reflect the seasonal and locational value of the power. Different peaking times in the northwest and southwest lead to large-scale transactions.
- **Real-Time Market and Reliability Services:** CAISO has certain agreements with generators to provide reliability services. The CAISO spreads the costs of these reliability services among the load-serving entities. In addition, the CAISO buys power in the real-time market to balance resources and loads and charges the load-serving entities whose short supply necessitated real-time purchases.

Greenhouse Gas Costs and Allowance Proceeds

Since January 1, 2013, electric utilities have been regulated under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the electric utilities must secure compliance instruments, known as offsets and allowances, and surrender them to the California Air Resources Board (CARB) to account for their GHG emissions. CARB holds quarterly allowance auctions where entities can buy and

[37] 2022 Padilla Report, Costs and Cost Savings for the RPS Program (PU Code § 913.3) – May 1, 2022

sell allowances. Utilities can also procure compliance instruments on secondary markets or through contractual arrangements.

The Cap-and-Trade Program requires the utilities to comply on their customers' behalf for the emissions associated with the energy customers use. For electric utilities, compliance costs come in the form of a direct compliance obligation for utility-owned generators and generators under contract (which must also buy and surrender compliance instruments), as well as indirect costs from wholesale market transactions or power contracts with pricing terms that include GHG emission costs.

Beginning in 2014, the electric utilities started introducing Cap-and-Trade Program related costs into electricity rates and distributing allowance proceeds to residential customers via the California Climate Credit, applied to customer bills twice a year. Small Business customers and emissions-intensive trade-exposed industrial customers also began to receive credits in 2014.

Utilities accrue costs for the Cap-and-Trade Program as both direct and indirect costs. In 2022, the electric utilities collectively included approximately $383 million in direct GHG costs into rates to bundled customers and returned approximately $910 million in allowance proceeds to bundled customers in the form of customer credits (see **Table 4.1**). The electric utilities returned another approximately $415M in allowance proceeds to unbundled customers in customer credits. Customers also incur indirect costs for the Cap-and-Trade Program when utilities purchase power from the spot market or other market purchases, where the cost of compliance is included as part of the purchase price. These Cap-and-Trade Program compliance costs are included in the "Purchased Power" row of Table 2.1 (2022 Electric IOU Authorized Revenue Requirements), but are not reported separately in this section.

Table 4.1: 2022 Summary of Greenhouse Gas Costs and Allowance Proceeds[38]

Utility	2022 Electric GHG Direct Costs Revenue Requirement[39]	2022 Electric Proceeds Distributed to Bundled Customers	2022 Electric Proceeds Distributed to Unbundled Customers
PG&E		($228,568,556)	($250,079,576)
SCE		($497,195,898)	($158,533,354)
SDG&E		($184,467,272)	($6,963,600)
Total	**$383,018,587**	**($910,231,726)**	**($415,576,530)**

[38] Proceeds recorded through September 30, 2022 and estimated through December 31, 2022. Costs recorded through August 31, 2022 and estimated through December 31, 2022. Costs for bundled customers only. In August 2021 CPUC passed D.21-08-026, which changed Cap-and-Trade proceed reporting requirements to allow for proceeds to be tracked separately for bundled and unbundled customers starting in 2022.

[39] Due to confidentiality, some cells have values that were redacted.

Each year, CARB allocates allowances to electric utilities on behalf of their ratepayers. The Cap-and-Trade Program requires the investor-owned electric utilities to sell all of these allowances at CARB's quarterly allowance auctions in the year they are allocated. The proceeds the utilities receive from the sale of GHG allowances must be used exclusively for ratepayer benefits, consistent with the goals of AB 32 (2006), CARB regulations, and as directed by the CPUC. Consistent with the direction in SB 1018 (2012), the CPUC has determined the methodologies the utilities should use to return proceeds to industrial customers[40], small business, and residential customers. Due to crediting changes ordered by the D.21-08-026 and first implemented for 2022, credits received by small businesses served by the electric utilities increased more than five-fold from $23 million in 2021 to $118 million in 2022.

In addition to customer credits, up to 15 percent of allowance proceeds may be used for clean energy or energy efficiency programs. AB 693 (Eggman, 2015) directed up to $100 million of allowance proceeds be allocated annually to solar energy systems in disadvantaged communities. In response, the CPUC established the Solar on Multifamily Affordable Housing (SOMAH) program in December 2017. In 2020, CPUC determined that as proceeds are available and there is adequate participation and interest in SOMAH program, allocation of funds to the SOMAH program will continue through June 30, 2026. For the second consecutive year, in 2022 SOMAH was funded at the full $100 million ceiling. In 2018, in response to AB 327 (Perea, 2013), the CPUC developed the Disadvantaged Communities Single-family Solar Homes program (DAC-SASH), the Community Solar Green Tariff (CSGT), and Disadvantaged Communities-Green Tariff (DAC-GT) programs to encourage growth of renewable generation among residential customers in disadvantaged communities.[41] These programs are funded first with allowance proceeds and, if those are exhausted, through public purpose programs (PPP) funds. Additionally, in 2019 the CPUC also approved use of $20.4 million by SCE for a Clean Energy Optimization Pilot, of which $10 million was appropriated from Cap-and-Trade funds in 2022. An inventory of demand side management programs funded out of the IOUs' GHG auction proceeds can be found in section V.

Other Factors Affecting Electricity Generation Costs

Prior sections have described many factors that cause energy generation and procurement costs to vary significantly between different types of procurement and over time. Natural gas prices are another factor that can have a significant effect on the cost of many types of generation:

> **Natural Gas Prices:** Natural gas prices cause generation costs to be more volatile than other forms of generation. Electric spot market purchases and cogeneration QFs costs fluctuate and track with gas prices. Natural gas bilateral

[40] Defined as emissions-intensive and trade-exposed by Public Utilities Code section 748.5.

[41] The DAC-SASH program is funded up to $10 million annual, and funding is provided as needed and available for the CSGT and DAC-GT programs.

contracts do not track as closely with gas prices, as most of the costs of those contracts are associated with capacity and not energy. Renewables contracts generally exhibit more cost stability because they are not reliant on gas prices.

If generation costs are significantly higher or lower than forecasted,[42] the affected utility must file an ERRA Trigger notification with the CPUC's Energy Division. If the utility does not believe that the difference will be within the authorized threshold amount within 120 days, it files an expedited ERRA application (Trigger) that corrects rates to be in line with the costs the utility is experiencing. The Trigger application maintains rate stability if the costs associated with fuel and purchased power vary greatly from forecasted amounts.

The CPUC conducts annual Compliance ERRA reviews that true-up any difference from the utility's forecasted revenue requirement to the actual costs incurred regardless of whether or not a Trigger application was filed.

In 2022, natural gas prices rose around the world. Demand for non-Russian gas increased quickly due to the war in Ukraine, while supply ramped up more slowly. In California, a hot summer was followed by early and sustained winter cold, which increased demand. There was lower supply of natural gas due to lower gas storage levels on the West Coast and natural gas pipeline outages, which reduced the supply available to the West. These demand and supply factors impacted the prices of natural gas in California, which reached record highs in the winter of 2022-2023.

Weather: Weather continues to play a role in varying electricity prices. For example, the summer heat waves in 2020 and 2022 throughout California caused electricity prices to spike to extreme highs during peak demand hours. 2021 was also a major drought year. Drought years in the western states mean less hydroelectric generation available and thus more reliance on natural gas-fired generation; all else equal, this tends to increase electricity prices. Additionally, there was particularly cold and wet weather in winter 2022-2023 that helped drive an increase in natural gas and electricity prices during that time. Variances in electric generation and procurement costs due to weather are addressed in the CPUC's annual ERRA Compliance and ERRA Forecast applications, as well as mid-year ERRA Trigger adjustments when warranted by particularly large electric price deviations from forecasts.

[42] The utility must alert the CPUC if a balance grows to greater than 4 percent more or less than revenue requirement per D. 02-10-062; if the balance is expected to cross 5 percent the utility must file an expedited application known as an "ERRA Trigger Application".

V. Demand-Side Management and Customer Programs

The Demand-Side Management (DSM) work that the CPUC oversees is characterized by a mix of energy efficiency (EE), demand response (DR), and distributed generation (DG) programs, serving all sectors of the California economy. For nearly half a century, the CPUC has overseen policies to encourage energy conservation, efficiency and load management. In 2003, the CPUC and the California Energy Commission adopted the Energy Action Plan to establish goals for the state's energy strategy.[43] The plan established that cost-effective energy efficiency and demand response are at the top of the loading order and are therefore the preferred means for meeting the state's growing energy needs, followed by renewable energy and distributed generation.

In addition, California has led the nation in customer-side solar and other DG technology market growth, supported by the Self-Generation Incentive Program (SGIP) enacted in 2000, and, later in 2006, the landmark California Solar Incentive (CSI) program, both overseen by the CPUC. For decades the CPUC has administered low-income EE programs (now called Energy Savings Assistance or ESA) to assist vulnerable populations in managing their energy bills,[44] and takes input on these and other programs from the Low-Income Oversight Board (LIOB) established by the Legislature in 2001.[45]

[43] The Energy Action Plan was updated in 2005 and 2008.

[44] PU Code Section 2790.

[45] SBX 2 (2001, Alarcon).

Table 5.1 shows the DSM and customer program costs recovered in rates.

Table 5.1: 2022 Demand Side Management and Customer Programs Costs ($000)[46]

	PG&E	SCE	SDG&E	Total
Energy Efficiency	236,204	318,470	35,349	**590,023**
Demand Response	71,802	28,031	12,766	**112,599**
California Solar Initiative	0	0	0	**0**
Self-Generation Incentive Program	59,819	56,000	0	**115,819**
Electric Program Investment Charge	41,163	75,098	0	**116,262**
New Home Solar Partnership[1]	0	41,730	0	**41,730**
California Alternative Rates for Energy Admin	213,392	(30)	34,000	**247,361**
Energy Savings Assistance[2]	(19,218)	0	4,222	**(14,996)**
Other PPP Programs	201,939	465,158	234,958	**902,056**
Other Regulatory	57,795	583,468	321,849	**963,132**
Total	**862,897**	**1,567,945**	**643,144**	**3,073,986**

1. PG&E's and SCE's negative amount (overcollection) will be credited to customers.
2. The ESA budget for 2021 is shown as $0 due to program costs offset by the previous year unspent funds.

Energy Efficiency

In 2003, the California Energy Action Plan set energy efficiency at the top of the loading order, determining that the state should maximize all cost-effective energy efficiency investment over both the short and long-term. In D.04-09-060, the CPUC translated this policy into specific annual and cumulative numerical goals for electricity and natural gas savings by utility service territory, which are updated periodically as provided for in that decision. The CPUC-adopted energy savings goals are expressed in terms of annual and cumulative gigawatt hours (GWh), million-therms (MMtherms), and peak megawatt (MW) load reductions.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of rates. The electric portion is funded through the Procurement Energy Efficiency Balancing Account (PEEBA) to reflect the avoided generation and transmission and distribution upgrades that result from reduced

[46] Revenue requirement for Demand Side Management, California Solar Initiative, Self-Generation Incentive Program, and other regulatory ($162 million for PG&E, $334 million for SCE, and $230 million for SDG&E) is collected through the distribution rate component.

electricity demand. The aggregated annual expenditures are approximately $540 million for 2021 and 2022 together (see **Table 5.2**).

Programmatic efforts in 2021 and the first three quarters of 2022 resulted in reported program savings of 1,113 GWh, 182 MW,and 69 MMtherms.[47] According to the EPA,[48] that is enough electricity savings to power about 99,381 homes for one year, and enough gas savings to avoid the need for about one-tenth of a coal power plant.

These programs support residential, public, commercial, industrial, and agricultural sectors to overcome barriers to improving energy efficiency and realize savings for the ratepayer. In addition to the directly quantifiable savings and benefits, the CPUC also supported programmatic activities targeted at the long-term transformation of consumer energy markets through emerging technology development, marketing, education, training, and other initiatives. However, the savings benefits associated with these efforts are difficult to quantify and the CPUC has historically not done so.

[47] Reported savings estimates are net and are available from CEDARS (https://cedars.sound-data.com/).

[48] Equivalencies estimated using the EPA Greenhouse Gas Equivalencies Calculator (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator).

Table 5.2: Energy Efficiency Savings and Expenditures from Non-Codes and Standards IOU Program[49]

Year	2022	2021	Grand Total[50]
All Investor-Owned Utilities			
Electric (GWh)	**394**	**719**	**1113**
Demand (MW)	**664**	**119**	**182**
Natural Gas (MMTh)	**22**	**46**	**69**
Carbon (1000 Tons CO2)	**235**	**450**	**685**
Total Expenditures ($M)	**$201**	**$339**	**$540**
PGE			
Electric (GWh)	249	387	**636**
Demand (MW)	53	67	**120**
Natural Gas (MMTh)	11	19	**30**
Carbon (1000 Tons CO2)	127	211	**338**
Total Expenditures ($M)	$87	$135	**$222**
SCE			
Electric (GWh)	122	260	**381**
Demand (MW)	7	40	**47**
Natural Gas (MMTh)	0	0	**0**
Carbon (1000 Tons CO2)	33	66	**99**
Total Expenditures ($M)	$43	$84	**$127**
SoCalGas			
Electric (GWh)	2	4	**7**
Demand (MW)	2	2	**4**
Natural Gas (MMTh)	11	24	**35**
Carbon (1000 Tons CO2)	64	142	**206**
Total Expenditures ($M)	$49	$82	**$131**
SDGE			
Electric (GWh)	21	69	**90**
Demand (MW)	1	10	**11**
Natural Gas (MMTh)	1	2	**3**
Carbon (1000 Tons CO2)	11	31	**41**
Total Expenditures ($M)	$22	$38	**$60**

[49] 2022 data does not include fourth quarter data which will be available May 1st, 2023; Savings data does not include REN/CCAs or Codes and Standards advocacy savings; Savings data is reported net, first-year savings; Data does not include Energy Savings Assistance Program savings and costs; Decimals have been rounded to the nearest whole number; IOU Expenditures are reported at the program level and are not broken down into gas vs. electric expenditures. The total EE budget for 2022 was $831 million.

[50] Totals are summed before rounding, then rounded to the nearest whole number.

Demand Response

Per D.17-12-003, Demand response is defined as "reductions, increases, or shifts in electricity consumption by customers in response to either economic signals or reliability signals." Effective demand response programs provide California ratepayers with various economic and environmental benefits, such as:

1) Saving ratepayer money by deferring capital expenditures to build power plants and transmission infrastructure that would otherwise be necessary to meet peak demand.

2) Decreasing the price of wholesale energy and avoiding the purchase of high-priced energy.

3) Providing greater reliability to the grid, which helps prevent blackouts.

4) Avoiding the consumption of fossil fuels which can reduce GHG emissions.

Evolution of Demand Response Programs

Demand Response (DR) programs were historically aimed at large commercial and industrial customers that can shed significant amounts of load as an immediate or day-ahead response. With the advent of smart meters, smart thermostats, batteries, and other smart devices, DR programs for residential customers were introduced and residential customer participation in DR has grown over time.

Some utility DR programs operate with the use of dynamic pricing programs and time-variant rates in which price signals encourage customers to shift their energy use to off-peak periods of the day when energy demand is lower, such as time of use (TOU), critical peak pricing (CPP), and real time pricing (RTP). Other utility managed demand response programs such as the Base Interruptible Program (BIP), Capacity Bidding Program (CBP), or Air Conditioning Cycling (A/C Cycling) are bid as a capacity resource into CAISO energy markets, enabling them to compete against generation bids and to be dispatched as needed by the CAISO.

More recently, DR programs managed by third-party DR providers have been enabled by CPUC policies encouraging a competitive DR marketplace. These programs provide customers with additional choices and stimulate competition to innovate.

The Demand Response Auction Mechanism (DRAM) pilot provides a pathway for third-party DR providers and their customers to receive resource adequacy (RA)-eligible capacity payments for providing load reduction services during periods of peak electricity demand and high energy market prices. Under the DRAM pilot, utilities procure RA capacity through competitive bids offered by third parties in an annual auction process.

Pursuant to CPUC decisions, the IOUs were authorized to conduct annual DRAM auctions, with the most recent DRAM procurement resulting in 210 MW (August capacity) of DR resources for delivery in 2023. The IOUs have authorization to conduct one more DRAM solicitation to procure DR capacity for 2024. Resource Innovations, formerly known as Nexant, completed a DRAM evaluation for 2018-2021 in May 2022. The future course of DRAM beyond 2024 is expected to be decided by the CPUC in the currently open A.22-05-022 proceeding.

As an alternative pathway to DRAM, the CPUC established a Load Impact Protocol review process to qualify third-party DR providers to provide DR capacity for resource adequacy (RA) to non-IOU load serving entities (LSE), such as community choice aggregators (CCA) and energy service providers (ESP). Six DR providers completed the review process and contracted with non-IOU LSEs to deliver RA-eligible DR capacity in 2022.

Summer Reliability

In response to the August 2020 rotating outages, the Commission expanded the role of demand response resources to help address reliability concerns due to extreme weather.

- D.21-03-056 in Phase I of the Summer Reliability proceeding established the Emergency Load Reduction Program (ELRP) as a pay-for-performance demand response program that compensates voluntary load reduction provided by a participating customer during a program event triggered in response to CAISO-declared grid emergencies. Customers eligible to participate in ELRP included directly enrolled non-residential customers, virtual power plant (VPP) aggregators, and customers with Electric Tariff Rule 21 exporting Distributed Energy Resources (DERs).

- D.21-12-015 in Phase II Summer Reliability proceeding increased the ELRP compensation rate to $2 per kWh of incremental load reduction achieved by the customer. Eligibility for participation in ELRP was expanded to non-residential aggregators, electric vehicle/charging station aggregators (including both V1G - vehicle charging and V2G - vehicle discharging into the grid), and nearly four million residential customers automatically enrolled in Power Saver Rewards. Program event triggers for residential customers were expanded to include Flex Alerts.

- Additionally, the CPUC adopted several enhancements to IOU DR programs, expanded the smart thermostat program to fund about 300,000 new thermostats in hot climate zones, with the customer required to participate in a supply-side

DR program, and directed PG&E and SCE to implement hourly dynamic rate pilots for agricultural water pumping and other end uses.

Future Demand Response

Future DR programs are expected to help integrate increasing amounts of renewable power onto the grid by shifting electric loads to periods of high renewable generation. There may also be a significant role for DR to alleviate electricity supply shortages in certain local areas of the state with constraints on transmission capacity. To facilitate this, the Commission in July 2022 opened a new rulemaking to establish demand flexibility policies and introduce hourly marginal-cost based electric rates to help enhance system reliability, reduce curtailment of renewable energy, and reduce electricity costs of service among other objectives. Two working groups in the rulemaking will draw on ideas from the June 2022 Energy Division staff whitepaper: Advanced Strategies for Demand Flexibility Management and Customer DER Compensation.[51] This rulemaking (R.22-07-005) supports the California Energy Commission Load Management Standards, which call for customers to have access to dynamic rates, updated at least hourly to reflect grid conditions, by 2027.

Customer Generation

The CPUC has taken actions that support the development of customer-sited distributed energy resources and related technologies by providing financial incentives to customers and project developers. Ratepayers fund Distributed Generation (DG) programs that provide financial incentives to participating customers including the Disadvantaged Community Single Family Solar Homes (DAC-SASH) Program, the Self-Generation Incentive Program (SGIP), and the Solar on Multifamily Affordable Housing (SOMAH) program. In addition, Net Energy Metering (NEM), soon to be joined by the net billing tariff (NBT), provides customer-generators with bill credits for power generated by their onsite systems that is fed back into the grid. In December 2022 the CPUC adopted the net billing tariff, which is the successor tariff to NEM that will go into effect in April 2023.

[51] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf

Table 5.3: 2022 GHG Auction Proceeds Funded Demand Side Management and Customer Programs ($000)[52]

	PG&E	SCE	SDG&E	Total
Disadvantaged Communities Single-Family Solar Homes, Green Tariff & Community Solar Green Tariff	30,919	5,068	1,042	**37,030**
Solar on Multifamily Affordable Housing[53]	46,222	48,711	19,465	**114,398**
Total	**77,141**	**53,779**	**20,507**	**151,428**

Disadvantaged Communities Single-Family Solar Homes (DAC-SASH), Disadvantaged Communities-Green Tariff (DAC-GT), and Community Solar Green Tariff (CSGT) Programs

AB 327 (Perea, Chapter 822, Statutes of 2013) required the Commission to develop “specific alternatives designed for growth [in adoption of renewable generation] among residential customers in disadvantaged communities.” The Commission determined that installations under the Solar on Multifamily Affordable Housing (SOMAH) Program (D. 17-12-022) should count towards the obligation to develop alternatives for DACs, but also recognized the need to develop multiple programs and tariff options to address the variety of barriers that residents of disadvantaged communities face in accessing renewable energy. Thus, D.18-06-027, adopted in June 2018, established three additional programs to provide households in DACs access to renewable energy: two rate programs (the DAC-Green Tariff (DAC-GT) and the Community Solar Green Tariff (CSGT) programs) and a direct-install solar program, the DAC Single-family Solar Homes (DAC-SASH) program. For these programs, DACs are defined as communities identified by CalEnviroScreen 4.0 as among the top 25 percent most impacted communities statewide, in addition to 22 census tracts in the highest 5 percent of CalEnviroScreen’s Pollution Burden that do not have an overall score in the top 25 percent. In December 2020 and October 2022, respectively, the Commission voted to expand the DAC-SASH and DAC-GT and CSGT program’s definition of DACs to include California Indian Country.

DAC-SASH provides incentives for income-qualified, single-family homeowners who live in DACs to install solar on their roofs. Modeled after the previously existing SASH

[52] Table 5.3 shows the Demand Side Management paid for by IOUs GHG proceeds.

[53] Solar On Multifamily Affordable Housing (SOMAH) program includes current year funding and prior year true-up amounts. A SOMAH funding year cannot exceed $100M per D.17-12-022 and Public Utilities Code 2870. The amounts in in this table are more than $100M since it includes prior-year true-up amounts which are not subject to a given year‘s $100M cap.

program, DAC-SASH has a budget of $10 million per year through 2030. A DAC-SASH Handbook developed by the selected statewide Program Administrator, GRID Alternatives, was approved by the Commission in September 2019. To date, DAC-SASH has helped install 1,513 rooftop solar systems, totaling 6.28 MW.

DAC-GT enables income-qualified, residential customers in DACs who may be unable to install solar on their roof to benefit from utility scale clean energy and receive a 20 percent bill discount. The program is modeled after the existing Green Tariff portion of the Green Tariff/Shared Renewables Programs and is available to customers who meet the income eligibility requirements for the CARE and FERA programs. To date, approximately 24,000 customers have been enrolled using interim Renewable Portfolio Standard (RPS) resources and 70 MW of new solar projects were approved, the first of which is scheduled to become operational in 2024.

CSGT enables residential customers in DACs who may be unable to install solar on their roof to benefit from a local solar project and receive a 20 percent bill discount. The communities work with a local non-profit or government "sponsor" to organize community interest and present siting locations to the utility or CCA; the sponsor can also receive an incentive for its efforts. The program has a capacity cap of 41 MW and is anticipated to begin enrolling customers in 2023.

D.18-06-027 also established that each IOU would file an Application for Review for their DAC-GT and CSGT programs by January 1, 2021. The Commission's Executive Director extended the deadline to May 31, 2022 at the IOUs request. On August 10, 2022, the Commission issued a ruling that consolidated the applications into a single proceeding, A.22-05-022. Concurrently, with the passage of AB 2316 (Ward, 2022) and AB 2838 (O'Donnell, 2022), the Commission has folded the legislative directive to review its existing customer renewable energy subscription programs including DAC-GT, CSGT and the Green Tariff Shared Renewables (GTSR) programs into this proceeding. This proceeding will review program goals, budget, capacity, design, implementation, and consumer protections and explore new authorization for the Commission to allow the IOUs to terminate their GTSR programs. It will also evaluate whether these programs achieve the specified goals of AB 2316 and will modify the programs as necessary and consider whether to adopt a new community renewable energy program.

Solar on Multifamily Affordable Housing (SOMAH) Program

AB 693 (2015) directed the CPUC to develop a program that provides financial incentives for the installation of solar energy photovoltaic (PV) systems on multifamily affordable housing properties throughout California. The CPUC issued D.17-12-022 that outlined the program design for the new SOMAH program in the service territories of PG&E, SCE, SDG&E, Liberty Utilities, and PacifiCorp. In addition to building on many of the program successes and lessons learned from the CSI-funded MASH Program, the SOMAH program seeks to:

- Direct up to $100 million annually from the electric IOUs' Greenhouse Gas Auction allowance value towards subsidized solar energy systems on multifamily affordable housing.[54]

- Encourage the development and installation of solar systems in California's disadvantaged and low-income communities.

- Develop, by December 31, 2030, at least 300 MW of installed solar generating capacity.

The SOMAH Program opened on July 1, 2019, with more than 200 applications received on day one. The SOMAH Program Administrator continues to develop and implement strategies to ensure a robust pipeline of applications. A recent program evaluation, completed October 2021, made recommendations for the SOMAH Program Administrator including streamlining the application process and estimated significant monthly bill reductions for tenants.[55] There is another program evaluation underway to be completed by June 2023 which will assess actual energy and bill benefits. As of January 2023, the program has 387 active applications, with 30 percent of these in disadvantaged communities. There are 74 completed projects with over a third in disadvantaged communities, and these projects in total received approximately $23.4 million in incentives. For completed projects, the average system size was 171 kW and were given an average incentive of $316,300. Active applications and completed projects together equaled 64.87 MW, or 22 percent of the way to the program's 300 MW goal.

Self-Generation Incentive Program (SGIP)

Established in 2001, SGIP provides incentives to support distributed energy resources that will result in reductions in GHG emissions and peak demand. SGIP is one of the longest-running DG incentive programs in the country. Since the program's inception, over $2.5 billion in SGIP incentives have been paid out or reserved to over 45,000 projects comprising almost 1.7 gigawatts of capacity. In 2022, almost $108 million was paid out or reserved to over 7,700 projects comprising 126 MW of capacity; all but $5.4 million went to energy storage systems.

- AB 209 (2022) authorized $900 million in legislatively appropriated state General Fund monies for the first time to SGIP. $630 million was proposed in the Governor's January 2023 budget for eligible low-income residential customers who install either new behind-the-meter solar PV systems paired with energy storage or new standalone energy storage systems. $270 million for general market incentives may be included in a future budget. In October 2022, the Assigned Commissioner issued a ruling seeking comment on implementing the funds and other improvements to the program. A Decision is expected to be adopted before the new funds become available on July 1, 2023.

[54] D.20-04-012 authorized funding collection through June 2026.

[55] SOMAH Phase 2 Program Evaluation by Verdant Associates, October 2021, can be accessed here: somah_phaseii_report_20211013_final.pdf (ca.gov)

- In March 2022 the CPUC approved a jointly filed Advice Letter to allow linear generators (power plants that directly convert motion along a straight line into electricity using energy from renewable natural gas) to participate as an SGIP-eligible renewable generation technology.

Additional Background on SGIP

- The program was reauthorized by SB 700 (2018) to continue ratepayer collections through 2024 and program administration through 2026. Pursuant to SB 700, the CPUC authorized ratepayer collections of $166 million annually for the years 2020 to 2024 in D.20-01-021 for a total of $830 million. The program funds are collected from PG&E, SCE, SDG&E, and SoCalGas.

- CPUC D.20-01-021 allocated the $830 million authorized in new ratepayer collections across the SGIP budget categories: 88 percent to energy storage and 12 percent to renewable generation. Within energy storage, an additional $512 million was allocated to the equity resiliency budget created in D.19-09-027. This budget provides the highest incentive level to vulnerable households and facilities that support vulnerable communities to enable these groups to enhance their resiliency in the face of wildfire risks and related de-energization events.

- CPUC D.21-12-031 allocated almost $67 million of unused accumulated funds to fund the waitlists in the respective SGIP Program Administrator service territories. Priority was given to Equity Resiliency Budget projects. Across the four SGIP Program Administrators, over 335 projects were funded from the waitlists.

- Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells and advanced energy storage systems. For non-residential systems, half of the incentive is paid up-front and half of the incentive is paid based on the performance of the technology over five years.

Net Energy Metering (NEM)

California's net energy metering (NEM) program allows customers who install eligible renewable electrical generation facilities to serve onsite energy needs and receive credits on their electric bills for surplus energy sent to the electric grid. Unlike the other programs in this section, the costs associated with NEM come from the intra-rate class cost shift (from NEM customers to non-NEM customers) rather than from program funds. Because retail rates include recovery of system costs that are not avoided by distributed generation, NEM bill credits for customer-generators cause a revenue shortfall that is recovered through increased rates for customers not participating in NEM (who on average have lower incomes than NEM customers).[56]

In January 2016, the CPUC approved a decision adopting a NEM successor tariff (NEM 2.0) for customers starting NEM service after each utility reached its statutory five percent NEM capacity cap. NEM 2.0 went into effect in SDG&E's and PG&E's territories 2016, and in SCE's territory in 2017. Customers on NEM 2.0 pay an interconnection fee and non-bypassable charges for public purpose programs and other initiatives that cannot be offset with surplus energy credits. [57] They also take service on a time-of-use rate plan service territory. In its 2016 decision (D.16-01-044), the CPUC stated its intention to later revisit the NEM successor tariff.

In 2019, the CPUC commissioned an independent evaluation of NEM 2.0.[58] The evaluation found that the tariff is cost-effective overall for NEM 2.0 participants, but not cost-effective from a combined participant/utility perspective or for non-participating ratepayers.[59] The study also found that after NEM 2.0 system installation, the average residential customer-generator pays much less, and the average nonresidential customer-generator pays more, than the estimated cost to serve them.[60]

In August 2020, the CPUC opened a proceeding, Rulemaking (R.) 20-08-020, to revisit the NEM successor tariff and enable California's tariff for customer-generators to better fulfill its AB 327 (2013) statutory requirements. After development of the proceeding's evidentiary record, on December 15, 2022, the CPUC adopted Decision (D.)22-12-056, which established the framework for the new net billing tariff.

The new tariff provides cost savings to new solar customers and also significantly reduces the cost shift paid by non-solar customers compared to the previous tariff, thus improving the equity of the tariff and helping to facilitate the state's building electrification goals.

The new tariff decouples import rates and export rates and mandates more cost-based price signals for customers. NBT customers will take service on a high-differential time-of-use rate that will discourage imports during the evening when the grid is the most expensive to operate and the generation mix has the highest GHG emissions. The tariff also creates hour-by-hour export price signals designed to encourage exports when the grid needs it most – for example, during late summer evenings. The combination of these two components creates a dynamic where customers are on average better off

56 See the evaluation of NEM 2.0 available at https://www.cpuc.ca.gov/nem2evaluation.

[57] For purposes of the NEM successor tariff, the relevant non-bypassable charges are: Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges.

[58] The draft and final reports are available at https://www.cpuc.ca.gov/nem2evaluation.

[59] The draft report found that NEM 2.0 is cost-effective from a combined participant/utility perspective due to a modeling error, but we report the final report's findings above for clarity on the conclusions that should be taken away.

[60] The study also provided analysis, not summarized here, regarding customers' energy usage before and after installing renewable energy generation systems on the NEM 2.0 tariff, effects on cost-effectiveness of the addition of energy storage or the removal of the federal investment tax credit, cost-effectiveness compared to NEM 1.0, characteristics of the NEM 2.0 participant and non-participant populations, and other topics.

financially purchasing solar paired with storage than simply purchasing solar. These tariff changes are expected to drive greater solar installations that are collocated with battery energy storage systems, which supports grid reliability.

Low-Income Programs

In addition to programs serving low-income customers and customers residing in DACs mentioned previously, the IOUs provide three ratepayer-funded energy assistance programs for qualifying low-income customers. The California Alternate Rates for Energy program (CARE) offers bill discounts off energy bills for low-income customers. The Family Electric Rate Assistance (FERA) program provides families of three or more, whose household income slightly exceeds the CARE allowances, with an 18 percent discount on their electricity bill. The Energy Savings Assistance program (ESA) provides no-cost in-home weatherization services, energy efficiency measures, and energy education to help eligible low-income households conserve energy, reduce energy costs and improve their health, comfort, and safety. The Energy Savings Assistance Common Area Measures (ESA CAM) program provides no-cost energy efficiency measures in common areas (e.g. hallways, lobbies) for income qualifying deed restricted multifamily properties.

California Alternate Rates for Energy (CARE)

The CARE program is a low-income energy rate assistance program that provides a discount on energy bills to qualifying low-income households. The CARE program is funded by non-exempt customers (exempt customers include CARE customers) as part of a statutory "public purpose program surcharge" that appears on utility bills. The income qualifications for the CARE program are households that are at or below 200 percent of the Federal Poverty Guidelines.

The CARE program was established in 1989 by Public Utilities Code Sections 739.1 and 739.2, which authorizes a 15 percent rate discount for qualifying low-income customers off their energy bills. In 2001, the minimum CARE rate discount was increased from 15 percent to 20 percent by CPUC D.01--06--010. However, due to a number of factors on how rate increases and new charges were allocated to customers, the effective discounts grew to over 40 percent for some CARE customers.

In October 2013, AB 327 (Perea, Chapter 61, Statutes of 2013) was passed requiring the IOUs to restructure the CARE discount rates and to set an effective electric rate discount between 30-35 percent. In compliance with AB 327 and D.15-07-001, the effective discounts were reduced to 35 percent for PG&E and SDG&E, and remain at 32.5 percent for SCE. These reductions occurred gradually to prevent rate shock.

As economic hardships for California residents increased over the course of the COVID-19 pandemic, participation in CARE increased with approximately 2.7 million new customer accounts added since March 2020 with approximately 970,500 of those added in 2022. In 2022, the program provided an estimated $2.1 billion in annual subsidies and served about five million low-income customers statewide.[61] A higher CARE subsidy does not result in a higher revenue requirement for the utility, but it does increase the rates that non-CARE customers pay. Even for these customers though, the CARE program surcharge has long been a small percentage of their energy bill. For example, in 2021, the CARE surcharge on a non-CARE residential monthly electric bill ranged from 3 to 4 percent of the total bill, which translates to an average of $2 to $5 a month. Similarly for residential gas bills, the CARE surcharge on a non-CARE residential monthly gas bill was about 2 percent of the total bill, which equals around $1 a month.[62]

PG&E's CARE subsidy in 2022 was approximately $985 million (electric and gas combined), compared to $666 million for SCE, $229 million for SDG&E (electric and gas combined), and $210 million for SoCalGas (see **Table 5.4**).

Table 5.4 2022 CARE Program Costs[63]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$801,324,709	$8,877,117	$810,201,825
	Gas	$184,057,249	$2,219,279	$186,276,528
SCE	Electric	$666,223,958	$7,289,721	$673,513,80
SDG&E	Electric	$205,993,118	$5,016,771	$211,009,889
	Gas	$22,624,235	$596,848	$23,221,083
SoCal Gas	Gas	$210,498,561	$8,557,557	$219,056,118
Total		**$2,090,721,830**	**$32,557,293**	**$2,123,279,123**

Energy Savings Assistance Program (ESA)[64]

The ESA program is a no-cost energy efficiency program that provides home weatherization services and energy efficiency measures to help low-income households conserve energy, reduce their energy costs/utility bills, and improve the health, comfort, and safety of the home. The program also provides information and education to promote energy efficient practices in low-income communities. Additionally, the ESA program has a multifamily component addressing building wide common areas (ESA CAM), providing energy efficiency measures for deed and non-deed restricted properties. ESA is funded by all utility customers as part of a statutory "public purpose program surcharge" that appears on utility bills.

[61] Some customers are enrolled in more than one program, for example SCE for electricity and SoCalGas for natural gas. Source: 2022 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

[62] Source: 2021 Investor-Owned Utility ESA-CARE Annual Reports, posted to Docket A.19-11-003.

[63] Source: 2022 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

[64] Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

Effective July 2022, the program expanded to a greater number of California low-income households at or below 250 percent of the Federal Poverty Guidelines.

The program's original objective was to promote equity and relieve low-income customers of the burden of rising energy prices. The program has evolved into a resource program that achieves energy savings while improving quality of life for low-income customers.

The CPUC initiated the first energy efficiency programs for low-income customers in the early 1980s. In 1990, the California legislature adopted and codified the ESA program in Public Utilities Code Section 2790 requiring the electrical and gas corporations to perform home weatherization services for low-income customers in their service territory, taking into consideration both the cost-effectiveness of the services and the policy of reducing hardships for low-income households. In 2007, the CPUC adopted a programmatic initiative in D.07-12-051 to provide all eligible customers the opportunity to participate in the ESA program and to offer participants with cost-effective energy efficiency measures in their residences by 2020, which was subsequently codified (Public Utilities Code Section 382(e))ensuring that, by the end of 2020, all eligible and willing low-income customers would have the opportunity to participate in the ESA program. The IOUs met this goal.

In June 2021, the CPUC issued D.21-06-015 establishing ESA budgets and program designs for program years 2021 to 2026. The decision moved away from setting ESA program goals based on number of households treated and towards deeper energy savings goals. In early 2022, IOUs began identifying highly vulnerable ESA customers in multiple need states (for example, customers who are both low-income and living in Disadvantaged Communities or also enrolled in Medical Baseline) and conducted competitive ESA solicitations to garner a wider number of applicants and diversify the ESA program workforce. In 2022, the first ESA pilots were launched to achieve the aim of providing deeper energy savings at the household level.

Customers enroll in the ESA program through various channels including leads from CARE program participants, door-to-door neighborhood canvasing, direct mail, email, community-based organizations, categorical enrollment, online, and community events. Marketing materials are available in multiple languages. ESA is an income-verified program; however, customers can enroll automatically if already participating in another financial assistance programs with similar criteria.[65] **Table 5.5** shows the 2022 ESA program costs. In 2022, ESA served approximately 208,178 households , achieved

[65] These are known as Categorically Eligible programs. The current list of programs include: Bureau of Indian Affairs General Assistance, CalFresh Benefits (federally known as the Supplemental Nutrition Assistance Program or SNAP and formerly known as Food Stamps), Healthy Families Category A & B, Head Start Income Eligible (Tribal Only), Low Income Home Energy Assistance Program (LIHEAP), Medicaid/MediCal, National School Lunch Program (NSL), Supplemental Security Income (SSI), Temporary Assistance for Needy Families (TANF), Women, Infant, and Children Program (WIC)

44 GWh and 1.7 MMtherms of annual energy savings.[66] In 2022, the ESA CAM program served 147 properties which together contain nearly 12,124 units and achieved annual energy savings of 3.4 GWh and 0.2 MMtherms.[67]

Table 5.5: 2022 ESA Program Costs[68]

Utility	Operations	ESA Year-To-Date Expenses 2022	ESA CAM Year-To-Date Expenses 2022*
PG&E	Electric and Gas	$126,879,863	$6,558,088
SCE	Electric	$56,605,479	$1,724,371
SDG&E	Electric and Gas	$14,396,968	$1,494,706
SoCalGas	Gas	$100,946,724	$2,658,870
Total		**$298,829,034**	**$12,436,035**

*ESA CAM is not a part of the investor-owned utilities' total revenue requirement as it is funded by previously unspent ESA Funds by D.16-11-022, modified by D.17-12-009.

Family Electric Rate Assistance (FERA)

The FERA program is a low-income electric rate assistance program that provides an 18 percent discount on electric bills to qualifying low-income households with three or more individuals. FERA is funded by a statutory "public purpose program surcharge" that appears on utility bills. The FERA program was designed to assist families that are ineligible for the California Alternate Rates for Energy (CARE) rate because their income levels are slightly above the CARE program limits.

The income limits of the FERA program range from 200 percent plus $1 to 250 percent of the Federal Poverty Guidelines. Public Utilities Code Section 739.1(f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based on their level of income and family size.

The FERA program was established in 2004 by CPUC D.04-02-057 as the Lower Middle Income Large Household program. In D.05-10-044, the lower income limits of the FERA program were raised to 200 percent plus $1 of the Federal Poverty Guideline levels, which correspond to the upper limits of the CARE program. In compliance with Senate Bill 1135 (Bradford, Chapter 412, Statutes of 2018) and Public Utilities Code section 739.12, the FERA program discount increased from 12 percent to 18 percent effective January 1, 2019.

[66] Final household treatment numbers will be available in IOU Annual Reports for Program Year 2022 on May 1, 2023.

[67] Source: 2022 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003. Final property, unit, and energy savings numbers will be available in IOU Annual Reports for Program Year 2022 on May 1, 2023.

[68] Source: 2022 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

D.21-06-015 established a 50 percent enrollment goal by 2023 and a 70 percent enrollment goal by 2026. The decision also approved FERA dedicated program management budgets and directed the utilities to create tailored marketing and outreach efforts to reach these program enrollment goals. The increase in income eligibility for the ESA program as of July 2022 allows for some cross-program marketing and enrollment between ESA and FERA.

PG&E's FERA subsidy in 2022 was approximately $17.2 million, compared to $11.48 million for SCE, and $6.9 million for SDG&E. At the end of 2022, approximately 74,799 households were enrolled in FERA out of an estimated 439,602 eligible households.[69] **Table 5.6** shows the 2022 FERA program costs.

Table 5.6: 2022 FERA Program Costs[70]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$17,196,193	$2,850,749	$20,046,942
SCE	Electric	$11,482,677	$876,827	$12,359,504
SDG&E	Electric	$4,692,214	$310,046	$5,002,260
Total		**$33,371,084**	**$4,037,622**	**$37,408,706**

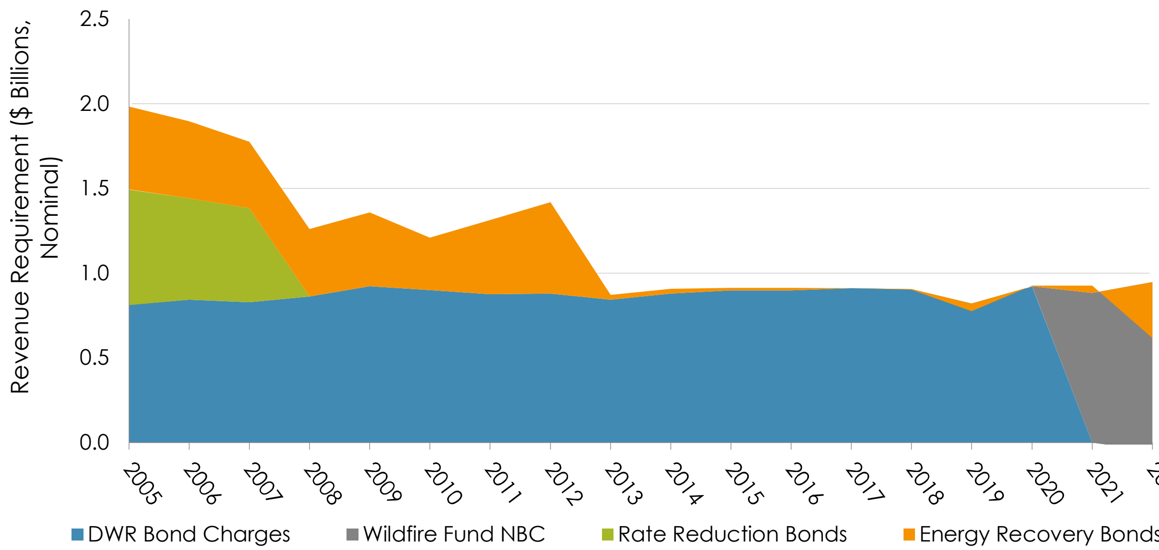
[69] Source: 2022 Investor-Owned Utility ESA-CARE-FERA Monthly Reports, posted to Docket A.19-11-003. Final program costs will be available in IOU Annual Reports for Program Year 2022 on May 1, 2023.

[70] Source: 2022 Investor-Owned Utility ESA-CARE-FERA Monthly Reports, posted to Docket A.19-11-003.

VI. Bonds, Regulatory Fees, and Legislative Program Costs

During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. Since the energy crisis, these bond costs have decreased from a peak of approximately $2 billion in 2005 to approximately $900 million through September 2020 and then were retired in 2021. As discussed in further detail below, beginning in October 2020, the bond charges were replaced by the Wildfire Fund Non-Bypassable Charge revenue requirement of $902.4 million, as illustrated in **Figure 6.1**.

Figure 6.1: Trends in Bond and Wildfire Fund Expenses ($ Billions)



Rate Reduction Bonds were issued in 1998 and paid back in full in 2007. AB 1890, the legislation that established the terms of energy restructuring, authorized these bonds to provide an immediate reduction in electric rates. Among other things, the legislation froze electric rates at June 1996 levels and reduced rates for residential and small commercial customers by 10 percent.

DWR bonds were issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis. As of September 30, 2020, enough funds were collected from ratepayers to retire the DWR bonds, and consequently the DWR bond charge expired.

As part of the CPUC and PG&E bankruptcy settlement agreement reached after PG&E's first bankruptcy in 2001, the utility was authorized to recover $2.2 billion as a Regulatory Asset. This was a separate and additional part of PG&E's rate base. The Energy Recovery Bonds were issued by PG&E in 2003 to reduce the financing cost of the Regulatory Asset to ratepayers. Charges associated with the Energy Recovery Bonds ceased in 2012.

On October 1, 2020, pursuant to AB 1054 (Holden, Chapter 79, Statutes of 2019) and CPUC Decision (D.) 19-10-056, the Wildfire Fund Non-Bypassable Charge (NBC) was implemented with an annual revenue requirement of $902.4 million combined for the large electrical utilities.[71] The 2020 Wildfire Fund NBC was equivalent to the expired DWR bond charge, and was identical in 2021, resulting in no 2021 bill increase to customers. The Wildfire Fund NBC supports the participation of large electrical utilities in the AB 1054 Wildfire Fund.

In addition, AB 1054 authorizes the CPUC to issue a financing order allowing IOUs to issue recovery bonds to finance the first $5 billion of approved wildfire mitigation capital expenditures in aggregate among the three large electric IOUs (PUC section 8386.3(e)). This program effectively saves ratepayers money by allowing lower cost financing compared to traditional utility financing mechanisms. The CPUC has thus far issued five financing orders under PUC Sec. 8386.3(e).

D.20-11-007 granted SCE's request to implement a fixed recovery charge and issue recovery bonds to finance $327 million of Grid Safety and Resiliency Program (GSRP) capital expenditures and D.21-10-025 granted SCE's request to implement a fixed recovery charge and issue recovery bonds to finance $526 million of GRC Track 1 & 2 Wildfire Mitigation capital expenditures. The resulting AB 1054 bond charges for SCE in 2022 appear in Table 6.1 under the category Other Regulatory. D.23-02-023 was issued on March 1, 2023 and any related fixed recovery charges will be reported next year.

Similarly, pursuant to AB 1054, PG&E filed Application (A.) 21-02-020 requesting authority to implement a fixed recovery charge and issue recovery bonds to finance up to $1.2 billion of approved wildfire mitigation capital expenditures. D.21-06-030 approved PG&E's request which ultimately resulted in a securitization bond issuance totaling $860 million. The related fixed recovery charges were implemented effective December 1, 2021, and the resulting $81.68 million revenue requirement for 2022 is included in Table 6.1 netted within the category Other Regulatory. D.22-08-004 authorized an additional recovery bond issuance for PG&E during 2022 and the related fixed recovery charges will be reported next year.

[71] CPUC D.19-10-056, October 24, 2019, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M318/K549/318549782.pdf.

Table 6.1 shows the Bond Expenses and Other Regulatory components of the 2022 revenue requirement for each of the large electric IOUs.

Table 6.1: 2022 Bond Expenses ($000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges	(135,562)	(143,910)	(48,519)	(327,991)
Rate Reduction Bonds	0	0	0	0
Energy Recovery Bonds	(330,602)	0	0	(330,602)
Wildfire Fund NBC	457,007	(446,976)	92,132	996,115
Other Regulatory	45,469	198,637	124,886	368,992
Total Net Amount	**36,312**	**501,703**	**168,499**	**706,514**

Fees

Fees include a variety of charges levied by federal, state, and local governments. For example, the CPUC Reimbursement Fee reimburses the State for the cost of regulating the utilities. **Table 6.2** shows the 2022 revenue requirement for regulatory fees. In total, this entire category of expenses accounted for roughly three percent of the 2022 revenue requirement. Some fees are included in the other revenue components. Only nuclear decommissioning costs are recovered separately through the Nuclear Decommissioning Adjustment Mechanism.

Table 6.2: 2022 Regulatory Fees ($000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC Reimbursement Fee[1]	100,624	100,183	0	200,807
Franchise Fee & Uncollectible Surcharge[2]	0	(318)	9,028	8,710
Catastrophic Events Memo Account	332,441	0	0	332,441
Hazardous Substance Mechanism	38,998	0	300	39,298
Nuclear Decommissioning[3]	48,368	3,230	184	51,783
Spent Nuclear Fuel	0	4,597	1,174	5,771
Major Emergency Balancing Account[4]	(10,840)	0	0	(10,840)
Wildfire Mitigation Plan Memo Account[5]	73,708	0	0	73,708
Fire Risk Mitigation Memo Account[6]	0	0	0	0
Total	**583,300**	**107,692**	**10,686**	**701,678**

1. SDG&E does not include the CPUC fee in the revenue requirements. SDG&E CPUC fees are a surcharge applied to customer bills and therefore are not included in the rates. The 2022 electric CPUC reimbursement fees for PG&E, SCE, and SDG&E were $0.00032/kWh.
2. Not reported elsewhere.
3. Includes Nuclear Decommission franchise fees and uncollectible expense as applicable.
4. For SCE and SDG&E, forecasts for emergency preparedness and response are approved as part of the GRC budget and not in a segregated balancing account.
5. SCE and SDG&E have not collected revenue for Wildfire Mitigation Plan Memo Account.
6. SCE and SDG&E have not collected revenue for Fire Risk Mitigation Memo Account.

Definition of Fees

- **CPUC Reimbursement Fee:** This is the annual fee to be paid by utilities to fund their regulation by the CPUC (California Public Utilities (PU) Code Section 401-443). The surcharge to recover the cost of that fee is ordered by the CPUC under authority granted by PU Code Section 433.
- **Franchise Fees:** Fees paid by a privately-owned utility to cities and counties for the right to use or occupy public streets and roads, and for permission to provide service in their jurisdictions. These fees are then redistributed to the cities and counties. In some cases, these fees are included in other cost categories and not separately determined in this report, as appears to be the case with PG&E.[72]
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected. There are large pending, uncollectible balances from COVID-19 related accounts that were not in rates in 2021. These will be partially offset with California Arrearage Payment Program (CAPP) from the State and will be reported in next year's AB 67 Annual Report.
- **Catastrophic Events Memorandum Account (CEMA)**: An account established to enable a utility to recover the costs associated with the restoration of service and utility facilities affected by a catastrophic event (e.g., an earthquake) or state of emergency declared by federal or state authorities.
- **Hazardous Substance Mechanism:** An account established to allow certain costs of investigating and remediating hazardous waste sites identified by the utilities.
- **Nuclear Decommissioning:** Nuclear decommissioning funds are established for the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Spent nuclear fuel is shown as a separate item.
- **Major Emergency Balancing Account:** Specific to PG&E, the MEBA recovers actual costs resulting from responding to major emergencies and catastrophic events not eligible for recovery through the CEMA. In some cases, costs relating to major emergencies that are found by the CPUC not to be eligible for recovery through the CEMA process may be recoverable through the MEBA.
- **Wildfire Mitigation Plan Memorandum Account:** In 2019, pursuant to SB 901 (2018), each electric utility opened an account to track its costs incurred to implement its annual wildfire mitigation plan and seek recovery at a later date. With the exception of SDG&E, the utilities (PG&E[73] and SCE[74]) have submitted applications to recover the costs recorded in this account. WMP memorandum accounts have essentially been converted into balancing accounts for WMP-related

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[72] PG&E reported $0 for franchise fees in 2021 and in several other year's past, suggesting that they may have been reported in other cost categories after recovery in surcharges, and not recorded here.

[73] In CPUC D.20-10-026, PG&E was authorized to recover partial revenue for its Wildfire Mitigation Plan Memorandum Account from December 2020 through April 2022.

[74] In CPUC D.21-01-012 and D.21-10-25, SCE was authorized to recover partial revenue for its Wildfire Mitigation Plan Memorandum Account begining on March 1, 2022.

activities since WMPs are recurring and not one-time expenses. This took place for each utility in its first general rate case after 2019.

- **Fire Risk Mitigation Memorandum Account:** In 2019, pursuant to SB 901 (2018), each electric utility was allowed to establish an account to enable it to track its costs incurred for fire risk mitigations, if any, that are not otherwise covered anywhere else, and seek recovery at a later date. With the exception of SDG&E, the utilities (PG&E[75] and SCE[76]) have submitted applications to recover the costs recorded in this account.

Legislative Program Costs

Various electric programs, operated by the IOUs, are mandated by the State of California. Most programs aim to provide California with clean energy, while some programs provide subsidies to various customer groups. Some bonds and regulatory fees may also be mandated by the State. **Table 6.3** shows the 2022 electric revenue requirement for the legislative mandates.

Table 6.3: 2022 California Mandated Programs Revenue Requirement ($000)

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Aliso Canyon Energy Storage	AB 2514	0	9,243	0	**9,243**
Bioenergy Market Adjusting Tariff Non-Bypassable Charge	SB 860, SB 1122	27,098	(8,301)	0	**18,797**
California Energy Systems for 21st Century	SB 96	0	0	0	**0**
California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	SB 1, AB 217, AB 2723	0	0	0	**0**
CPUC Fee	Public Utilities Code § 431-432	100,624	107,500	0	**208,124**
Demand Response [77]	SB 73, SB 1414, AB 793 & AB 719	79,888	43,155	13,219	**136,263**
Department of Water Resources Bond	AB 1X and D. 01-03-081	(135,562)	0	(48,519)	**(184,081)**
Disadvantaged Communities - Single-Family Affordable Solar	AB 327	30,919	5,068	1,042	**37,030**

[75] In CPUC D.20-10-026, PG&E was authorized to recover partial revenue for its Fire Risk Mitigation Memorandum Account from December 2020 through April 2022.

[76] In CPUC D.21-01-012 and D.21-10-25, SCE was authorized to recover partial revenue for its Fire Risk Mitigation Memorandum Account begining on March 1, 2022.

[77] Demand Response includes Demand Response Auction Mechanism and IDSM, as applicable.

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Homes, Green-Tariff, Community Solar Green Tariff					
Economic Development Rate Balancing Account (EDRBA)	Public Utilities Code § 740.4(a) and 740.4(c)			577	**577**
Electric Program Investment Charge/New Solar Homes Partnership Program	Public Utilities Code § 399.8, SB 1, SB 32, SB 350 & SB 854, AB X1 15, AB 66, AB 523, AB 802, AB 1890, AB 2140, AB 2218	41,163	75,098	19,157	**135,418**
Energy Efficiency	SB 350, AB 1330, AB 802, AB 32, AB 1890, AB 841	236,204	318,470	39,571	**549,245**
Energy Savings Assistance Program/California Alternate Rates for Energy Program Administrative Expense	Public Utilities Code § 2790, § 382, SB 580, SB 691, AB 327, AB 793, AB 2140, AB 2857	236,429	69,653	178,924	**485,006**
Family Electric Rate Assistance[78]	SB 987, SB 1135	15,754	0	5,714	**21,468**
Green Tariff Shared Renewables	SB 43	0	1,037	0	**1,037**
Greenhouse Gas Cost[79]	AB 32 (SB 43, SB 854, AB 57)	95,882	154,562	20,337	**270,780**
Greenhouse Gas Revenue Return	AB 32 (SB 43 & AB 57)	(525,666)	(647,824)	(190,908)	**(1,364,398)**
Hazardous Substance Memorandum Account	AB X1 6	38,998	2,227	311	**41,536**
Mobile Home Park Program	Public Utilities Code § 2791-2799	22,571	14,518	12,957	**50,046**
Net Energy Metering[80]	AB 1070	0	0	0	**0**
New Solar Homes Partnership Program	SB 1, AB X1 14, AB X1 15	0	0	(10,397)	**(10,397)**
Officer Compensation	SB 901	0	0	147	**147**
Renewable Portfolio Standard[81]	SB 1078, SB 350, SB 100	1,994,448	2,435,502	538,418	**4,968,369**

[78] Family Electric Rate Assistance includes administrative expenses, as applicable.

[79] PG&E's Greenhouse Gas Cost is presented as a five-year average.

[80] Net Energy Metering includes solar system contracts and disclosures, as applicable.

[81] RPS revenue requirements do not distinguish the above-market portion. PG&E's RPS value is presented as a five-year average.

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Residential Uncollectible Balancing Account (RUBA)	SB 598	0	0	3,200	**3,200**
San Diego Unified Port District	AB 628	0	0	1,420	**1,420**
San Joaquin Valley Disadvantaged Communities Pilot and Data Gathering	AB 2672	0	0	0	**0**
School Energy Efficiency Stimulus Program	AB 841	67,062	88,094	62,899	**218,055**
Self-Generation Incentive Program	SB 700, AB 970, AB 1144	59,819	56,626	20,069	**136,515**
Smart Grid	SB 17, AB 32	3	0	0	**3**
Solar on Multifamily Affordable Housing	SB 692, AB 693	46,222	48,711	19,465	**114,398**
Statewide Marketing Program	AB 793	0	0	0	**0**
Summer Reliability OIR	July 31, 2021 Proclamation of Emergency from Governor Newsom	31,613	0	0	**31,613**
Total Rate Adjustment Component	AB 1X	0	0	80,000	**80,000**
Transportation Electrification Programs[82]	SB 350, AB 1082, AB 1083, AB 628	26,503	32,148	26,046	**84,697**
Tree Mortality Non-Bypassable Charge	SB 43, SB 859	12,597	(39,896)	9,363	**(17,936)**
Wildfire and Natural Disaster Resiliency Rebuild (WNDRR)	SB 1477	20,259	23,525	5,988	**49,771**
Wildfire Fund Non-Bypassable Charge	AB 1054	457,007	446,976	92,132	**996,116**
Wildfire Hardening Fixed Recovery Charge	AB 1054	(3,636)	0	0	**(3,636)**
Total		**2,976,200**	**3,236,092**	**901,134**	**7,113,426**

[82] Transportation Electrification includes pilots, as applicable.

VII. Natural Gas Utility Ratepayer Costs

The CPUC determines the reasonableness of natural gas utility operational costs, gas cost allocation among customer classes, and gas rate design for PG&E, SDG&E, and SoCalGas.

Natural gas utility costs may be categorized into the following three main components: 1) core procurement costs, 2) costs of operating the natural gas transportation system and providing customer services, and 3) costs associated with gas public purpose programs (PPP).

Unlike its process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Utilities procure gas supplies for core gas customers (primarily residential and small commercial) only. Utilities' gas procurement is subject to a sharing incentive under which utilities receive a reward if they procure gas at costs below certain benchmarks and incur a penalty if procured at costs above the benchmarks. The mechanism provides utilities with a financial incentive to purchase gas for core ratepayers at costs that are beneficial to the utility, with part of the savings being shared with ratepayers. Procurement costs shown in this report pertain to these core customers. Large volume noncore customers, such as industrial or electric generation, procure their own gas supplies and, therefore, procurement costs of their gas usage are not included herein. Core gas procurement costs are recovered in utility gas procurement rates, which are adjusted monthly. The commodity gas price is the cost component with the greatest variability. Monthly changes in gas commodity prices on customer bills provide consumers with price signals that they can use to adjust their gas usage. The tables below show costs for 2022 and a comparison of 2022 to prior years.

Table 7.1 shows the 2022 natural gas revenue requirement by components.

Table 7.1: 2022 Gas Revenue Requirement by Key Components ($000)

	PG&E	SDG&E	SoCalGas	Total
Core Procurement	1,110,950	327,665	2,365,840	3,804,455
Transportation	4,224,068	623,563	4,117,214	8,964,845
Public Purpose Programs	320,391	45,691	349,488	715,570
TOTAL	**5,655,409**	**996,919**	**6,823,542**	**13,484,870**

Table 7.2 shows historical revenue requirement for 2016-2022 for the key components.

Table 7.2: Historical Gas Utility Revenue Requirement ($000) (2016-2022)

	2016	2017	2018	2019	2020	2021	2022
Core Procurement	2,053,769	2,465,182	2,067,169	2,226,842	1,822,180	2,475,283	3,804,455
Transportation	6,753,286	6,275,397	6,458,407	7,418,647	7,869,039	8,264,942	8,964,845
Public Purpose Programs	639,808	647,260	604,622	650,968	575,600	630,382	715,570
Total	**9,446,863**	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**	**13,484,870**

As **Table 7.2** shows, the 2022 total natural gas utility costs increased by 18.6 percent from 2021 compared to the 10.8 percent increase for 2020-2021.

Figure 7.1 show the trends in natural gas utility revenue requirements by components.

Figure 7.1: Historical Trends in Gas Utility Revenue Requirement Components ($ Billions)

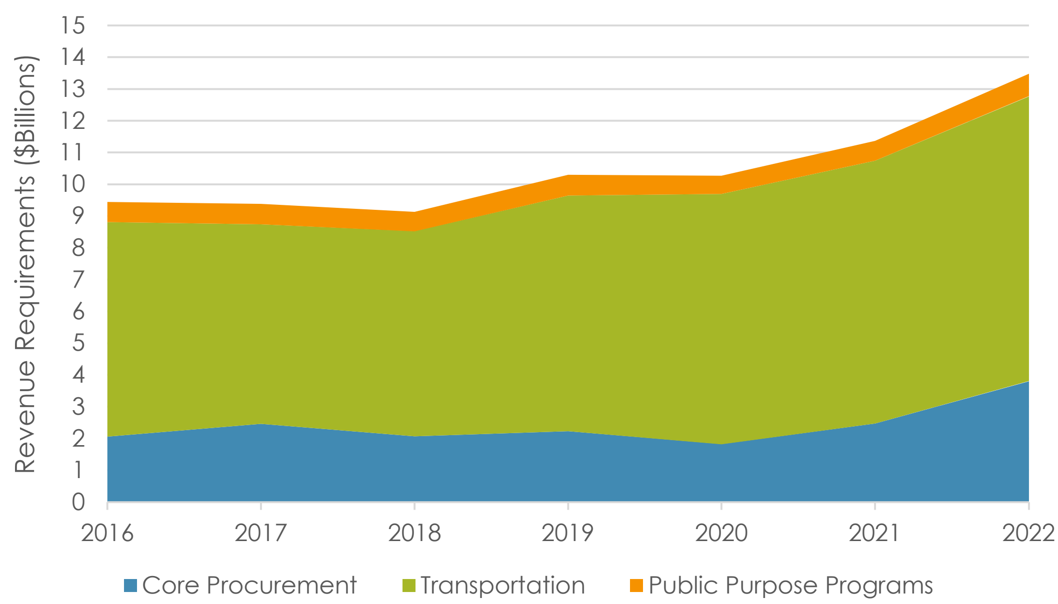


Table 7.3 shows the trends in natural gas revenue requirement for each of the utilities.

Table 7.3: Historical Revenue Requirement ($000) By Utility

	2016	2017	2018	2019	2020	2021	2022
PG&E	4,789,682	4,610,816	4,470,985	4,587,569	4,484,635	4,926,879	5,655,409
SoCalGas	4,095,158	4,191,353	4,113,388	5,042,690	5,009,906	5,637,250	6,832,542
SDG&E	562,023	585,670	545,825	666,198	772,278	806,478	996,919
Total	**9,446,863**	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**	**13,484,870**

As Table 7.3 shows, revenue requirements increased for each of the utilities from 2021 to 2022. PG&E's revenue requirement increased by 14.8 percent, while SoCalGas' and SDG&E's revenue requirements increased by 21.2 percent and 23.6 percent, respectively.

Changes in the components of revenue requirement are summarized below and discussed in more detail in their respective sections.

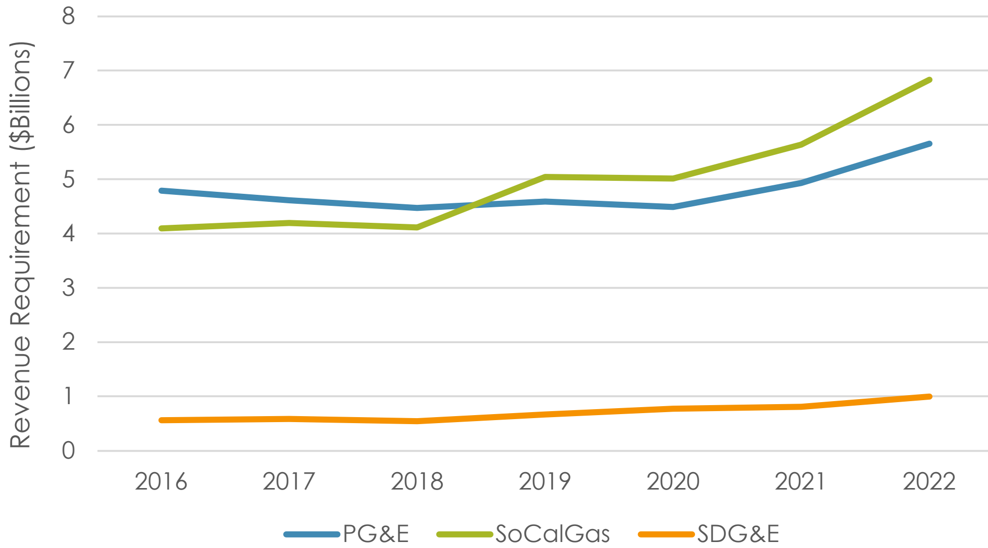
Total core procurement costs increased by 53.7 percent from 2021 to 2022. PG&E's core procurement costs increased by 28.3 percent, SoCalGas by 66.9 percent, and SDG&E by 70.5 percent.

Gas utility transportation and distribution costs increased by 8.5 percent from 2020 to 2021. Each utility saw an increase, with PG&E's transportation costs increasing by 11.7 percent, SoCalGas' by 5.7 percent, and SDG&E's by 6.5 percent.

A third component of costs are the natural gas PPP costs, which increased by 13.5 percent from 2021 to 2022. PPP costs for PG&E increased by 15.4 percent, while SoCalGas and SDG&E saw increases of 7.8 percent and 59.4 percent, respectively. PPP costs include expenditures for CARE and low-income energy-efficiency programs, which are designed to subsidize low-income households' utility bills.

Figure 7.2 show the trends in natural gas utility revenue requirements by utilities.

Figure 7.2: Historical Trends in Gas Utility Revenue Requirement ($ Billions)



Core Gas Procurement

The gas utilities recover the actual cost of procurement of natural gas for core customers through a rate component called the gas procurement rate. The gas procurement rate changes every month to reflect the most current commodity prices for natural gas.

Core gas customers in California have the option to choose between utility gas procurement service and gas procurement service from other entities called Core Transport Agents (CTAs). Even with CTAs, over 80 percent of core gas customers still receive gas procurement service from the utility. In contrast, almost all larger, noncore natural gas consumers (industrial customers or electric generators) procure their own natural gas supplies using non-utility suppliers. The procurement costs shown in this section reflect only the utilities' costs of providing procurement service to core customers.

Core procurement costs include the various costs associated with procuring natural gas supplies for a utility's core gas customers, such as the cost of the commodity, interstate pipeline capacity costs, hedging costs, and other costs. However, the major component of core procurement costs is the cost of the commodity itself.

Due to a significant decrease in the price of natural gas since mid-2008, the state's natural gas utilities' procurement costs decreased by 40 percent from 2014 to 2020.

However, beginning in 2021, core procurement costs have seen significant increases. From 2020 to 2021, aggregated costs across the three IOUs increased by 35.8 percent, driven by an increase in natural gas commodity prices. Factors contributing to the price increase are varied and are currently being examined. The following reasons, though likely not exhaustive, have had noted impacts on commodity prices. First, gas production struggled to match the increase in demand resulting from post-pandemic economic recovery. Second, cold and extreme weather, including a polar vortex event in early 2021, increased heating demand and put upward pressure on gas prices. Third, pipeline infrastructure issues and outages reduced capacity of natural gas delivery to California. Finally, there were also global increases in liquefied natural gas (LNG) prices, which drove an increase in exports, particularly to Europe and Asia.

Core procurement costs continued to increase through 2022 for similar reasons. Like in 2021, commodity prices have been the primary driver of core procurement cost increases in 2022. Since last fall, natural gas prices have been higher on the West coast (California, Oregon, and Washington) than the rest of the country.

First, LNG exports have significantly increased, particularly due to the Russian invasion of Ukraine and subsequent market disruptions. This geopolitical situation has put pressure on US gas markets and has increased price volatility as the marginal supply to balance any supply/demand shortfall in the US is the supply being exported out of the US to global markets.

Second, prices have continued to increase through the end of 2022 due to colder than average weather. For example, from November 2022 through the end of the year, SoCalGas recorded 487.9 "Heating Degree Days" (HDD)[83], about 82 HDDs higher than the average for the same time period.

Third, issues on gas pipelines and below average levels of natural gas in storage in the West Coast have reduced the amount of natural gas available to purchase. Specifically, the El Paso Natural Gas pipeline has had restrictions on both its northern and southern systems. Its southern system has been restricted by 15 percent since the explosion in Arizona since August 2021. Its northern system has also been restricted by 15 percent since December 15, 2022, due to maintenance issues. While the southern system has been returned to full capacity since February 15, 2023, the northern system restrictions are ongoing. In addition, the limited supplies in the SoCalGas system resulted from ongoing maintenance and outages at other locations, preventing SoCalGas to transport gas. This includes: 1) ongoing maintenance since October 2021 at Needles/Topock, which has limited supply volumes from the El Paso and Transwestern pipelines. 2) unplanned Line 4000 pipeline repair, which limited Transwestern supply into the SoCalGas system. 3) Southern Zone maintenance from November to December 2022, which limited supplies to Ehrenberg.

[83] SoCalGas uses Heating Degree Days to measuer the coldness of winter weather.

Current storage levels are also lower than normal. Overall storage on the West Coast is currently about 31 percent lower than the five-year average. PG&E stated that storage levels maintained by market participants at facilities owned by independent third parties are impacting natural gas prices. For example, the Gill Ranch storage facility located near Fresno, CA, began limiting gas withdrawals in December 2022 due to water issues in its reservoirs, with no current schedule to return to full capacity. SoCalGas has also stated that its storage levels are below average. Although SoCalGas' storage level was at a seven-year high entering winter on November 1, 2022, steep withdrawals through December 2022 resulted in storage levels lower than 2021.

Pursuant to the Natural Gas Act of 1978 (NGA) and subsequent amendments, the cost of the natural gas commodity itself is deregulated. Neither the CPUC nor FERC regulate the wholesale price of natural gas. FERC regulates the cost of interstate transmission of natural gas to California, and the CPUC regulates the cost of intrastate transmission and distribution. FERC policy allows customers to resell such transportation rights bundled with the natural gas commodity at market rates.

FERC possesses broad powers under NGA Section 4A, added by the Energy Policy Act of 2005 (EPAct), to investigate and penalize anticompetitive behavior of the interstate natural gas transmission under its jurisdiction. FERC's enforcement powers also encompass broad market investigations into events with abnormally large consequences on gas and electric costs and reliability.

Table 7.4 and **Figure 7.3** show the historical revenue requirement for natural gas core procurement.

Table 7.4: Historical Core Procurement Revenue Requirement ($000)

	2016	2017	2018	2019	2020	2021	2022
PG&E	1,020,570	1,158,601	879,270	935,782	770,337	865,924	1,110,950
SoCalGas	912,847	1,154,731	1,048,393	1,134,044	923,497	1,417,147	2,365,840
SDG&E	120,352	151,850	139,506	157,016	128,346	192,212	327,665
Total	**2,053,769**	**2,465,182**	**2,067,169**	**2,226,842**	**1,822,180**	**2,475,283**	**3,804,455**

Figure 7.3: Historical Natural Gas Core Procurement Revenue Requirement ($ Billions)

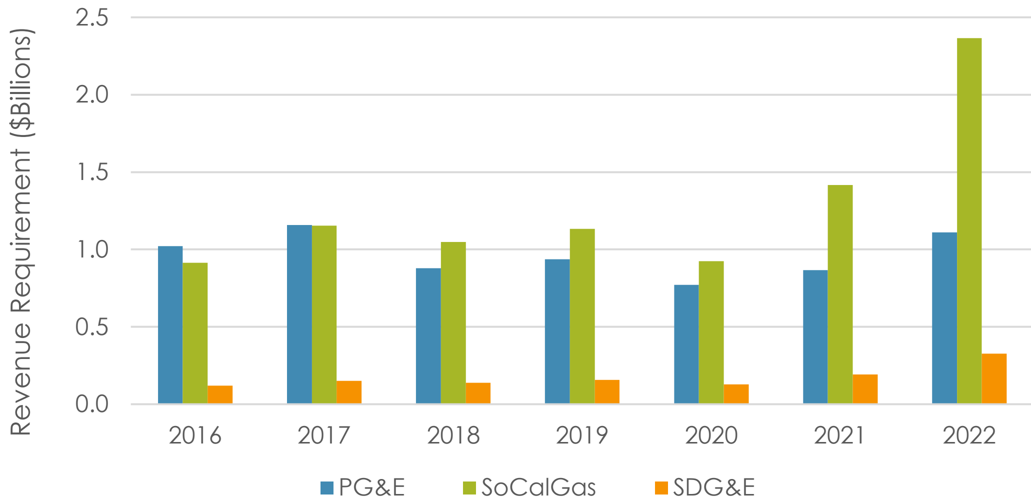


Table 7.5 shows the change in revenue requirement for core procurement.

Table 7.5: Percentage Change in Revenue Requirement for Core Procurement (2016-2021)

	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
PG&E	13.5%	(24.1%)	6.4%	(17.7%)	12.4%	28.3%
SoCalGas	26.5%	(9.2%)	8.2%	(18.6%)	53.5%	66.9%
SDG&E	26.2%	(8.1%)	12.6%	(18.3%)	49.8%	70.5%
Total	**20.0%**	**(16.1%)**	**7.7%**	**(18.2%)**	**35.8%**	**53.7%**

In 2022, core gas procurement costs accounted for 28.2 percent of total revenue requirement. **Table 7.5** shows an overcall core procurement increase for all three IOUs, with an aggregate increase of 53.7 percent. PG&E, SoCalGas, and SDG&E saw increases of 28.3 percent, 66.9 percent, and 70.5 percent, respectively. These increases were driven by commodity prices, as discussed above. For PG&E, however, annual GRC revenue increases for core backbone and storage as approved in D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service, also contributed to an increase in core procurement. For SoCalGas and SDG&E, storage costs are included in the transportation rate.

From 2020 to 2021 overall core procurement increased for each of the three IOUs, with an aggregate increase of 35.8 percent. The large increase in SoCalGas and SDG&E core procurement prices were due to increased commodity prices and supply disruptions due to a long-term outage on the El Paso interstate pipeline to Southern California.

From 2019 to 2020, overall core procurement decreased for each of the three IOUs, with an aggregate reduction of 18.17 percent. For PG&E, core procurement costs decreased due to reduced gas sales forecast volume and reduced commodity price. SoCalGas and SDG&E also saw decreases from 2019 to 2020 due to decreases in core consumption due to COVID-19, warmer weather, and lower commodity prices.

From 2018 to 2019, overall core procurement increased for each of the three utilities. The 7.72 percent increase in 2019 was due to the cold winter and IOUs' spot market purchases. In 2019, core gas procurement costs accounted for about 22 percent of the total utility costs.

From 2017 to 2018, overall gas procurement costs decreased by 16.1 percent. This decrease was reflected in the large reduction in core procurement costs (24 percent) for PG&E in 2017-2018. Procurement costs decreased by smaller margins for SDG&E (8 percent) and SoCalGas (9 percent) due toconstraints on the SoCalGas system.

From 2016 to 2017, there were increases in core procurement costs for the three major utilities. Procurement costs increased by 13.5 percent for PG&E. SoCalGas and SDG&E saw larger increases of approximately 26 percent, likely in response to system issues with storage and pipeline capacity.

Gas Transmission, Distribution, and Storage Costs

The CPUC authorizes natural gas distribution utilities' revenue requirements for operating their extensive natural gas transmission, distribution, and storage systems and for providing various customer services. These costs have steadily increased in recent years. The bulk of these revenue requirements are determined by the CPUC in the utilities' rate cases.

Table 7.6 shows historical revenue requirement for transportation for 2016-2022. With the recent emphasis on safety and replacement of aging infrastructure, the CPUC has authorized increased revenue requirement for all three major gas utilities with respect to transmission and distribution. Specifically, increases in total authorized revenue requirement for transmission, distribution, storage, and customer services, combined under the "transportation"[84] category, have increased by 32.7 percent from 2016 to 2022. These costs increased by 20.9 percent, 44.5 percent, and 52.4 percent for PG&E, SoCalGas, and SDG&E, respectively.

[84] PG&E's authorized revenue requirement for storage is included in core procurement rate category.

Table 7.6: Historical Transportation Revenue Requirement ($000)

	2016	2017	2018	2019	2020	2021	2022
PG&E	3,494,033	3,184,277	3,343,689	3,389,751	3,531,809	3,783,288	4,224,068
SoCalGas	2,850,105	2,693,301	2,741,585	3,550,769	3,723,109	3,896,051	4,117,214
SDG&E	409,148	397,819	373,133	478,127	614,121	806,478	623,563
Total	**6,753,286**	**6,275,397**	**6,458,407**	**7,418,647**	**7,869,039**	**8,264,942**	**8,964,845**

Table 7.7 shows the change in revenue requirement for transportation.

Table 7.7: Percentage Change in Revenue Requirement for Transportation (2016-2022)

	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
PG&E	(8.9%)	5.0%	1.4%	4.2%	7.1%	11.7%
SoCalGas	(5.5%)	1.8%	29.5%	4.9%	4.6%	5.7%
SDG&E	(2.8%)	(6.2%)	28.1%	28.4%	(4.6%)	6.5%
Total	**(7.1%)**	**2.9%**	**14.9%**	**6.1%**	**5.0%**	**8.5%**

Transportation costs represented 66.5 percent of total utility gas costs in 2022. **Table 7.7** shows that gas transportation costs increased by 8.5 percent from 2022. The increase in transportation costs for PG&E from 2021 to 2022 was 11.7 percent, driven by increases from various balancing accounts, including the Wildfire Expense Memorandum Account (wildfire insurance related costs authorized for recovery), the Risk Transfer Balancing Account (recovery of incremental wildfire insurance costs), and the Residential Uncollectibles Balancing Account. SoCalGas and SDG&E saw smaller increases in transportation costs. For SoCalGas, the increase was driven by an increase in the GHG program costs and Low Emission Vehicle program costs. Similarly, SDG&E had increases in its GHG program costs.

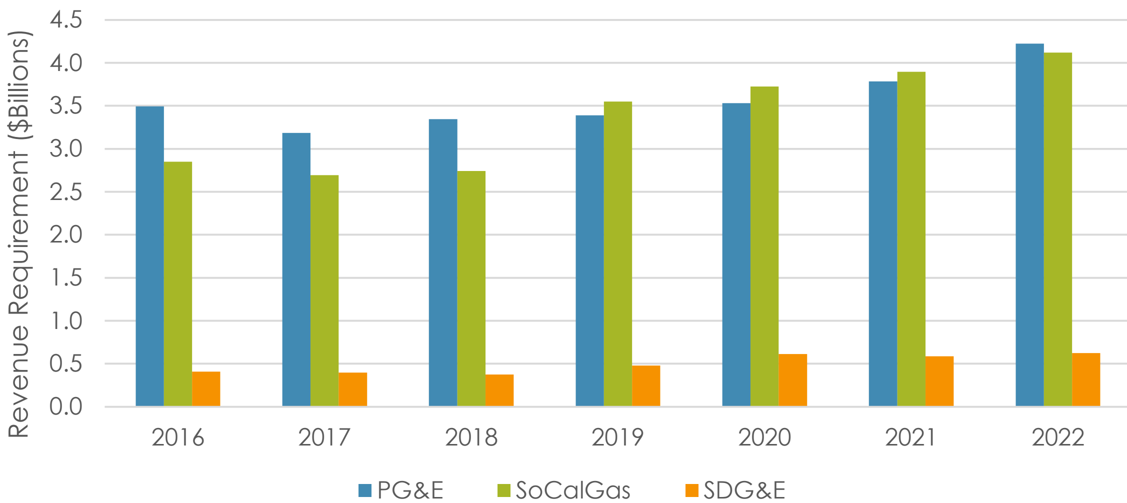
From 2020 to 2021, the increase in transportation costs for PG&E was due to increases in "Other Balancing Account Balances" for costs of Distribution Integrity Management Program (DIMP) and the GHG Program. The increase in transportation costs for SoCalGas was due to increases in Distribution, DIMP, and Transmission Integrity Management Program (TIMP) costs. The decrease was transportation costs for SDG&E is due to a decrease in DIMP costs.

From 2019 to 2020, the increase in aggregate Transportation revenue requirement of the three IOUs was predominantly accounted for by an increase in "Other Balancing Account Balances" ($328 million) and in Distribution and DIMP taken together ($208 million). These were offset by smaller decreases in several programs that were part of the Transportation revenue requirement.

A major factor in the increase in 2019 total transportation costs was that, for the first time for SoCalGas and SDG&E, GHG Program Costs and Proceeds (see further discussion below) were included in the transportation costs.

Figure 7.4 shows the historical revenue requirement for transmission, distribution, and storage.

Figure 7.4: Historical Natural Gas Transportation Revenue Requirement ($ Billions)



Legislative Program Costs

Several natural gas programs operated by the IOUs are under State mandates, apart from those under CPUC mandates. Among these, two large components are: (1) Greenhouse Gas Costs and Allowance Proceeds; and (2) Gas Public Purpose Program (PPP) Costs, discussed in detail below. Information on the applicable State-Mandates (including PUC Sections) for covered programs is included in Appendix B for Gas Costs.

Table 7.8 shows the 2022 revenue requirement for State-Mandated natural gas programs.

Table 7.8: 2022 State Mandated Programs Revenue Requirement ($000)

	PG&E	SDG&E	SoCalGas	Total
Self Generation Incentive Program (SGIP)	12,990	1,545	16,268	**30,803**
California Solar Initiative (CSI)	8,115	806	1,411	**19,933**
CPUC Fee[85]	29,100	N/A	N/A	**29,100**
Franchise Fee Surcharge (G-SUR)	15,955	3,800	28,403	**48,158**
Greenhouse Gas (GHG) Program	104,603	58,119	460,400	**623,122**
Energy Efficiency (EE) Programs	43,408	8,380	107,145	**158,933**
Low Income Energy Efficiency (LIFE)	93,802	8,041	0	**101,843**
Public Interest RD&D and State Board of Equalization (BOE) Administrative Fees	11,454	1,930	12,955	**26,339**
California Alternate Rates for Energy (CARE) Program	171,727	27,340	229,388	**428,455**
School Energy Efficiency Stimulus (SEES) Program	N/A	6,989	N/A	**6,989**
Total	**491,154**	**116,950**	**855,970**	**1,464,074**

Greenhouse Gas Compliance Costs and Allowance Proceeds

Since January 1, 2015, natural gas utilities have been covered under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the natural gas utilities must buy compliance instruments (offsets and allowances) and surrender them to the California Air Resources Board (CARB) to account for GHG emissions associated with the combustion or oxidation of fuels they provide to customers in California (less any amount delivered to covered entities that supply their own compliance instruments to CARB). CARB holds quarterly allowance auctions where entities can buy and sell allowances. The IOUs can also procure compliance instruments on secondary markets or through contractual arrangements.
CARB allocates some allowances to natural gas utilities on behalf of their ratepayers. The Cap-and-Trade Program requires the investor-owned natural gas utilities to sell an increasing share of these allowances at CARB's quarterly allowance auctions and use the proceeds for the benefit of ratepayers, starting at 25 percent of their allocated allowances in 2015 and increasing at a rate of 5 percent per year through 2030 (when 100 percent will be sold for ratepayer benefit). For 2022, natural gas utilities were required to sell 60 percent of allocated allowances for ratepayer benefit. The proceeds from the sale of GHG allowances must be used exclusively for ratepayer benefit,

[85] SDG&E and SoCalGas did not include the CPUC Fee in the revenue requirement reported here, but they do collect this fee as a separate charge on utility bills. As of December 2022, gas CPUC reimburse fees for PG&E, SDG&E, and SoCalGas are $0.003/therm (CPUC Resolution M-4866)

consistent with the goals of AB 32 (Nunez, Chapter 488, Statutes of 2006), CARB regulations, and as directed by the CPUC. The CPUC has determined the methodologies the utilities should use to return proceeds. D.15-10-032 and D.18-03-17 instructed natural gas utilities to return proceeds to residential ratepayers each April as an on-bill credit, with each residential ratepayer receiving an equal share of their utilities' available proceeds.

In addition to customer credits, pursuant to SB 1477 (Stern, Chapter 378, Statutes of 2018), starting in Fiscal Year 2019-20, $50 million of allowance proceeds will be used for building decarbonization pilot projects each year through Fiscal Year 2022-23.[86] In addition, for 2022 and 2023, D.20-12-031 directs the collective gas IOUs to allocate $20M annually to incentivize in-state biomethane production.

Beginning in 2015, the natural gas utilities started tracking Cap-and-Trade Program related costs and allowance proceeds. However, these costs and credits were not introduced into customer rates until July 1, 2018.[87] PG&E provided the 2018 credit in October 2018 and the 2019 credit in April 2019. SDG&E and SoCalGas distributed their 2018 and 2019 credits together in April 2019. All investor-owned natural gas utilities now distribute the natural gas California Climate Credit annually in April.

In 2021, the natural gas utilities collectively introduced approximately $886 million in GHG costs into rates and returned approximately $577 million in allowance proceeds to customers (see **Table 7.9**).

Table 7.9: 2022 Greenhouse Gas Costs and Allowance Proceeds[88]

	2022 Natural Gas GHG Revenue Requirement	2022 Natural Gas Proceeds Distributed to Customers
PG&E	$367,818,589	($244,947,809)
SDG&E	$58,171,807	($51,133,728)
SoCalGas	$460,298,316	($280,938,850)
Total	**$886,288,712**	**($577,020,387)**

[86] Fiscal Year begins July 1. Funds for FY2019 were collected out of 2020 allowance proceeds, alongside FY2020 funding.

[87] D.18-03-017 instructed the natural gas utilities to net compliance costs against proceeds for the 2015-2017 period and either (1) amortize costs over a 12-month period starting in July 2018 if costs exceeded proceeds or (2) distribute the net proceeds in 2018 as a climate credit if proceeds exceeded costs. D.18-03-017 also ordered that 2018 GHG compliance costs be amortized in rates over an 18-month period starting July 2018.

[88] Revenue requirement and proceeds based on 2022 forecasted amounts. Proceeds excludes $105 million set aside for the SB1477/Building Initiative for Low-Emissions Development program and Technology and Equipment for Clean Heating program and biomethane incentives (D.20-12-031).

Gas Public Purpose Program (PPP) Costs

The CPUC also authorizes costs for three main categories of gas PPPs: energy efficiency (EE) and low-income EE, the CARE subsidy, and the gas public interest research and development program administered by the California Energy Commission. Gas PPP costs are determined in various CPUC proceedings associated with the particular type of gas PPP. Gas PPP costs have increased since 2008 but are a relatively small part of total costs.

Revenue requirement authorized by the CPUC in 2022 for natural gas PPPs increased by 13.5 percent from 2021. Gas PPP costs made up 5.3 percent of total utility revenue requirement in 2022. PG&E had a 15.4 percent increase, primarily driven by funding for its Energy Savings Assistance (ESA)[89] program.[90] SoCalGas' PPP costs increased by 7.8 percent, driven by an increase in its California Alternative Rates for Energy (CARE) program. SDG&E had the greatest percentage increase of 59.4 percent driven by its Energy Efficiency[91] and Low-Income Energy Efficiency programs.[92]

Gas PPP costs are recovered through the gas PPP surcharge on core and non-exempt noncore customers.[93] Only non-CARE customers pay for the CARE subsidy portion of the gas PPP surcharge. The gas PPP surcharges are changed annually through advice letter filings, incorporating the revenue requirements for the gas PPPs adopted in CPUC proceedings.

Table 7.10 and **Figure 7.5** show the historical revenue requirement for public purpose programs.

Table 7.10: Historical Public Purpose Programs Revenue Requirement ($000)

	2016	2017	2018	2019	2020	2021	2022
PG&E	275,079	267,938	248,026	262,036	182,489	277,667	320,391
SoCalGas	332,206	343,321	323,410	357,877	363,300	324,052	349,488
SDG&E	32,523	36,001	33,186	31,055	29,811	28,663	45,691

89 Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

90 PG&E's PPP funding for ESA was lower in 2021 compared to 2022 for the following reasons: 1) In 2021, PG&E included a credit of $29M in rates related to unspent funds from prior funding cycles. 2) The funding approved in 2021 for the ESA program was $54M, approximately $17.6M less than in 2022. 3) The ESA balancing account was overcollected in 2021 vs an undercollection in 2022, driving an additional $24M increase.

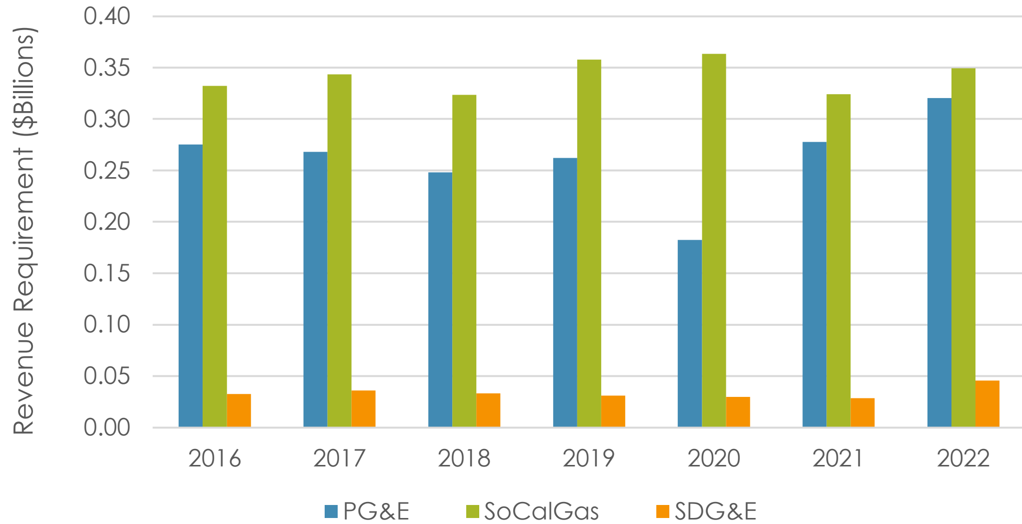
91 For SDG&E's EE programs, the main driver in the increase is due to a refund of overcollection (unspent and uncommitted funds) in 2021 that did not have an equivalent in 2022. In 2022, any unspent and uncommitted funds were re-allocated to SEESPBA as dictated by D.21-01-004.

92 SDG&E's LIEE costs in 2021 were zero. For LIEE, in 2021, D.20-08-033 noted to prioritize the use of unspent and uncommitted funds before any new revenue collection to fund bridge period activities. The authorized budgets for 2021 – 2026 were approved in D.21-06-015, which were then sought for collection in 2022 in AL 3027-G-A.

93 Noncore customers exempt from a gas PPP surcharge include electric generators, pursuant to Article 10 of the Public Utilities Code.

Total	**639,808**	**647,260**	**604,622**	**650,968**	**575,600**	**630,382**	**715,570**

Figure 7.5: Historical Revenue Requirement for Gas Utility Public Purpose Programs ($ Billions)



Appendices

A digital copy of the appendices can be found at:

https://www.cpuc.ca.gov/AB67Report

Appendix A: Historical Electric Revenue Requirements 2022-2018

2022 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**4,245,003**	**5,093,206**	**1,119,102**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	167,655	2,304,369	20,216
General Rate Case Revenues		CPUC Decisions	2,068,041	694,344	184,078
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,136,532	Included with Qualifying Facilities	410,545
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	341,602	2,094,493	701,225
Other		CPUC Decisions, Resolutions	(468,826)	0	(196,963)
Transmission Total			**2,948,943**	**1,390,045**	**772,822**
Reliability Services	FERC Order 459		6,802	(66,884)	149
Transmission Access Charge	FERC		312,445	156,960	(275,612)
Transmission Owner Rate Case Revenues	FERC		2,629,695	1,412,489	1,064,885
Other - FERC Rate Case Revenues	FERC		0	(112,520)	(22,459)
Other			0	0	5,859
Distribution Total			**6,106,297**	**7,457,937**	**1,624,992**
General Rate Case Revenues		CPUC Decisions	6,106,297	7,457,937	1,624,992
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**42,628**	**7,827**	**1,358**
Demand Side Management and Customer Programs Total*			**1,310,435**	**886,782**	**668,847**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,819	56,000	0
California Solar Initiative		CPUC Decisions	0	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	71,802	28,031	12,766
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,737	318,470	0
Energy Efficiency (non-PUC 399.8)			115,467	0	35,349
Electricity Program Investment Charge		CPUC Decisions	41,163	75,098	0
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	(19,218)	0	4,222
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	213,392	(30)	34,000
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	38,193
Other PPP		CPUC Decisions, Resolutions	201,939	253,444	234,958
Other		CPUC Decisions, Resolutions	505,334	155,769	309,359
Other Regulatory Total*			**461,224**	**578,891**	**12,790**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	332,441	0	0
Hazardous Substance Mechanism		CPUC Decisions	38,998	0	300
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	100,624	100,183	0
Other		CPUC Decisions, Resolutions	(10,840)	478,708	12,490
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(135,009)**	**0**	**0**
Wildfire Fund NBC	AB 1054	CPUC Decisions	**457,007**	**(143,910)**	**43,614**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**19,093**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(330,602)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**(318)**	**9,028**
Electric Total			**15,105,926**	**15,270,459**	**4,271,646**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2021 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,073,429**	**5,237,899**	**1,413,699**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	114,252	3,042,520	9,907
General Rate Case Revenues		CPUC Decisions	2,075,071	697,827	183,152
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,502,239	Included with Qualifying Facilities	659,328
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	380,681	1,481,544	643,541
Other		CPUC Decisions, Resolutions	1,185	16,009	(82,229)
Transmission Total			**2,035,538**	**1,253,026**	**736,175**
Reliability Services	FERC Order 459		10,316	(774)	(242)
Transmission Access Charge	FERC		57,898	258,290	(274,401)
Transmission Owner Rate Case Revenues	FERC		1,967,324	1,086,756	1,023,524
Other - FERC Rate Case Revenues	FERC		0	(91,246)	(21,410)
Other			0	0	8,704
Distribution Total			**5,595,486**	**6,587,686**	**1,599,694**
General Rate Case Revenues		CPUC Decisions	5,595,486	6,587,686	1,599,694
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**78,836**	**(43,059)**	**1,252**
Demand Side Management and Customer Programs Total*			**504,703**	**529,779**	**468,880**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	56,000	20,070
California Solar Initiative		CPUC Decisions	7,955	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	71,840	(1,706)	14,905
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	84,151	123,058	0
Energy Efficiency (non-PUC 399.8)			137,026	0	45,454
Electricity Program Investment Charge		CPUC Decisions	51,378	61,520	12,096
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	0	0	0
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	176,631	112,992	130,081
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	18,778	128,441	58,097
Other		CPUC Decisions, Resolutions	(102,908)	49,475	188,177
Other Regulatory Total*			**669,090**	**432,214**	**6,970**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	128,139	82,373	0
Hazardous Substance Mechanism		CPUC Decisions	35,480	0	80
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	100,348	100,183	0
Other		CPUC Decisions, Resolutions	405,123	249,658	6,890
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**0**	**0**	**0**
Wildfire Fund NBC	AB 1054	CPUC Decisions	**403,357**	**388,714**	**90,159**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**13,483**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**24,387**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**8,283**	**4,494**
Electric Total			**14,384,826**	**14,394,543**	**4,334,807**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2020 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,514,686**	**5,514,150**	**1,507,396**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	183,050	3,124,621	6,701
General Rate Case Revenues		CPUC Decisions	2,238,948	735,315	183,153
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,851,969	Included with Qualifying Facilities	857,111
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,235,381	1,642,236	514,612
Other		CPUC Decisions, Resolutions	5,337	11,978	(54,182)
Transmission Total			**2,469,714**	**949,095**	**559,089**
Reliability Services	FERC Order 459		(36,546)	0	624
Transmission Access Charge	FERC		490,935	45,336	(287,001)
Transmission Owner Rate Case Revenues	FERC		2,015,324	962,976	858,000
Other - FERC Rate Case Revenues	FERC		0	(59,218)	(19,166)
Other			0	0	6,632
Distribution Total			**4,988,079**	**4,777,874**	**1,517,842**
General Rate Case Revenues		CPUC Decisions	4,988,079	4,777,874	1,517,842
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**89,909**	**(39,847)**	**1,048**
Demand Side Management and Customer Programs Total*			**161,861**	**286,496**	**462,716**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	56,637	20,070
California Solar Initiative		CPUC Decisions	7,955	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	74,097	21,483	14,736
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	98,941	46,541	0
Energy Efficiency (non-PUC 399.8)			(62,284)	0	71,388
Electricity Program Investment Charge		CPUC Decisions	97,834	76,900	16,280
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	71,412	65,808	13,145
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	91,616	(8,531)	124,112
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	18,300	(13,920)	52,512
Other		CPUC Decisions, Resolutions	(295,863)	41,578	150,473
Other Regulatory Total*			**439,683**	**98,209**	**8,064**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	301,787	51,626	0
Hazardous Substance Mechanism		CPUC Decisions	29,836	0	164
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	47,117	46,584	0
Other		CPUC Decisions, Resolutions	60,943	0	7,900
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(974)**	**(5,400)**	**(1,100)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**427,327**	**428,069**	**66,926**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**16,840**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**3,669**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**3,181**
Electric Total			**14,093,952**	**12,008,645**	**4,142,002**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2019 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,388,555**	**5,926,553**	**1,668,615**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	181,551	2,719,189	7,566
General Rate Case Revenues		CPUC Decisions	2,156,844	670,615	244,650
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,931,130	Included with Qualifying Facilities	746,366
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,041,266	2,494,399	735,655
Other		CPUC Decisions, Resolutions	77,763	42,350	(65,622)
Transmission Total			**2,206,039**	**1,016,889**	**634,909**
Reliability Services	FERC Order 459		(24,241)	2,977	115
Transmission Access Charge	FERC		500,276	45,336	(265,539)
Transmission Owner Rate Case Revenues	FERC		1,736,739	1,039,554	900,051
Other - FERC Rate Case Revenues	FERC		(6,735)	(70,978)	(7,255)
Other			0	0	7,537
Distribution Total			**5,004,292**	**3,881,203**	**1,296,667**
General Rate Case Revenues		CPUC Decisions	5,004,292	3,881,203	1,296,667
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**79,414**	**(27,773)**	**(590)**
Demand Side Management and Customer Programs Total*			**323,135**	**(38,479)**	**512,218**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	55,998	20,069
California Solar Initiative		CPUC Decisions	7,955	3,840	2,002
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	68,419	37,997	11,838
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	92,009	92,892	0
Energy Efficiency (non-PUC 399.8)			73,624	0	104,038
Electricity Program Investment Charge		CPUC Decisions	89,885	76,095	17,138
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	129,493	63,617	5,829
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	57,758	(1,288)	38,000
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	3,381	(10,615)	123,934
Other		CPUC Decisions, Resolutions	(259,241)	(357,015)	189,369
Other Regulatory Total*			**70,252**	**46,584**	**5,270**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	4,800	0	0
Hazardous Substance Mechanism		CPUC Decisions	39,657	0	270
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	48,009	46,584	0
Other		CPUC Decisions, Resolutions	(22,214)	0	5,000
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(4,057)**	**(5,437)**	**(434)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**376,681**	**366,979**	**77,388**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**(136,983)**	**0**	**12,493**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(46,396)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**705**	**5,165**
Electric Total			**13,260,932**	**11,167,224**	**4,211,701**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2018 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,668,922**	**5,934,570**	**1,822,448**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	182,537	2,594,336	43,088
General Rate Case Revenues		CPUC Decisions	1,981,324	750,267	242,986
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,068,222	Included with Qualifying Facilities	691,131
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,398,617	2,352,938	887,777
Other		CPUC Decisions, Resolutions	38,223	237,030	(42,534)
Transmission Total			**2,146,305**	**1,024,468**	**502,821**
Reliability Services	FERC Order 459		170,611	4,136	734
Transmission Access Charge	FERC		430,524	(26,963)	(304,074)
Transmission Owner Rate Case Revenues	FERC		1,556,910	1,162,882	813,492
Other - FERC Rate Case Revenues	FERC		(11,740)	(115,588)	(13,302)
Other			0	0	5,970
Distribution Total			**4,702,384**	**4,663,722**	**1,299,314**
General Rate Case Revenues		CPUC Decisions	4,702,384	4,663,722	1,299,314
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**22,625**	**4,400**	**(939)**
Demand Side Management and Customer Programs Total*			**328,882**	**181,450**	**566,662**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,849	55,998	0
California Solar Initiative		CPUC Decisions	8,292	6,000	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	41,271	42,854	19,358
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,806	312,268	0
Energy Efficiency (non-PUC 399.8)			251,626	0	112,520
Electricity Program Investment Charge		CPUC Decisions	96,989	69,840	47,060
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	82,946	62,540	16,684
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	38,391	(3,259)	(7,000)
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	(26,720)	18,112	93,832
Other		CPUC Decisions, Resolutions	(344,568)	(382,903)	284,208
Other Regulatory Total*			74,607	0	1,318
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
Hazardous Substance Mechanism		CPUC Decisions	36,183	0	223
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	38,133	0	0
Other		CPUC Decisions, Resolutions	292	0	1,095
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	(1,171)	0	0
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	408,607	406,524	91,076
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	(79,700)	0	29,399
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	(3,773)	0	0
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	0	4,243	6,301
Electric Total			13,267,690	12,219,378	4,318,400

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix B: Historical Natural Gas Revenue Requirements 2022-2018

2022 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**1,110.950**	**2,365,840**	**327,665**
Core Gas Supply Portfolio		CPUC Decisions	686,247	2,343,527	327,665
Other		CPUC Decisions	421,314	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	(4,707)	0	0
Incentive Mechanism		Report	8,096	22,313	0
Transportation Total			**3,783,288**	**3,896,051**	**585,603**
Distribution		CPUC Decisions	2,094,595	3,143,713	469,428
Gas Pipeline Integrity Mgmt. (DIMP)			1,527,705	68,665	17,934
PSEP			0	98,973	38,689
SoCalGas Only - SIMP			0	23,651	0
SoCalGas Only - Aliso Canyon			0	0	0
Transmission		CPUC Decisions	0	0	0
Gas Pipeline Integrity Mgmt. (TIMP)			0	57,108	10,295
PSEP			0	23,827	3,036
Advanced Metering Infrastructure		Report	0	(77,757)	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,268	1,545
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	8,115	1,411	806
Annual Earning Assessment (AEAP)		CPUC Decisions	4,875	(267)	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	136,377	0
Haz Substance Mechanism (HSM)		CPUC Decisions	90,018	284	291
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	16,765	0
Core Pricing Flexibility Program		CPUC Decisions	0	323	0
Non-core competitive load growth program		CPUC Decisions	0	1,066	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	302,489	108,574	17,757
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	11,714	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	15,955	28,403	3,800
AB 32 Cap-And-Trade			21,909	9,430	1,863
GHG Program			104,603	460,400	58,119
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	320,391	349,488	45,691
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	43,408	107,145	8,380
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	93,802	0	8,041
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,454	12,955	1,930
Calif Alternate Rates for Energy (CARE) Program	PUC Section 739.1		171,727	229,388	27,340
School Energy Efficiency Stimulus (SEES) Program	AB 841		0	0	6,989
GAS TOTAL			**5,655,409**	**6,832,542**	**996,919**

Appendix B (cont.)

2021 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**865,924**	**1,417,147**	**192,212**
Core Gas Supply Portfolio		CPUC Decisions	475,721	1,406,003	192,212
Other		CPUC Decisions	370,549	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	16,136	0	0
Incentive Mechanism		Report	3,518	11,144	0
Transportation Total			**3,783,288**	**3,896,051**	**585,603**
Distribution		CPUC Decisions	2,130,066	2,971,090	442,148
Gas Pipeline Integrity Mgmt. (DIMP)			1,323,885	272,922	53,177
PSEP			0	184,223	36,113
SoCalGas Only - SIMP			0	23,096	0
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	0	0	0
Gas Pipeline Integrity Mgmt. (TIMP)			0	105,021	17,064
PSEP			0	49,394	2,897
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,272	1,545
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	13,138	5,979	816
Annual Earning Assessment (AEAP)		CPUC Decisions	5,343	(315)	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	68,598	0
Haz Substance Mechanism (HSM)		CPUC Decisions	81,857	2,801	95
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	16,450	0
Core Pricing Flexibility Program		CPUC Decisions	0	333	0
Non-core competitive load growth program		CPUC Decisions	0	1,794	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	68,273	223,229	44,135
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	7,576	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	9,643	18,229	3,352
AB 32 Cap-And-Trade			(2,059)	9,591	2,058
GHG Program			103,476	184,057	25,333
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**277,667**	**324,052**	**28,663**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	78,051	109,736	1,677
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	22,922	0	0
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,217	12,755	1,230
Calif Alternate Rates for Energy (CARE) Program	PUC 739.1		165,477	201,561	25,756
School Energy Efficiency Stimulus (SEES) Program	AB 841		0	0	4,541
GAS TOTAL			**4,926,879**	**5,637,250**	**806,478**

Appendix B (cont.)

2020 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**770,337**	**923,497**	**128,346**
Core Gas Supply Portfolio		CPUC Decisions	388,032	910,691	128,346
Other		CPUC Decisions	370,475	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	11,830	0	0
Incentive Mechanism		Report	0	12,806	0
Transportation Total			**3,531,809**	**3,723,109**	**614,121**
Distribution		CPUC Decisions	2,150,472	2,834,463	429,735
Gas Pipeline Integrity Mgmt. (DIMP)				56,726	16,208
PSEP				123,832	62,577
SoCalGas Only - SIMP				22,463	
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,170,454	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				31,559	9,023
PSEP				34,743	7,766
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,271	2,060
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	8,477	22,759	1,401
Annual Earning Assessment (AEAP)		CPUC Decisions	2,937	304	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	38,678	0
Haz Substance Mechanism (HSM)		CPUC Decisions	68,836	2,647	204
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	15,793	0
Core Pricing Flexibility Program		CPUC Decisions	0	688	0
Non-core competitive load growth program		CPUC Decisions	0	1,913	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	16,138	241,218	47,992
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,994	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	6,099	19,568	2,919
AB 32 Cap-And-Trade			24,294	9,696	2,286
GHG Program			35,018	249,788	31,950
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**182,489**	**363,300**	**29,811**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	70,279	93,255	812
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	(9,378)	134,474	11,572
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,172	11,338	3,053
Calif Alternate Rates for Energy (CARE) Program			111,416	124,233	14,374
GAS TOTAL			**4,484,635**	**5,009,906**	**772,278**

Appendix B (cont.)

2019 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**935,782**	**1,134,044**	**157,016**
Core Gas Supply Portfolio		CPUC Decisions	506,105	1,117,245	157,016
Other		CPUC Decisions	422,266	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	4,848	0	0
Incentive Mechanism		Report	2,563	16,799	0
Transportation Total			**3,389,751**	**3,550,769**	**478,127**
Distribution		CPUC Decisions	2,085,766	2,796,303	402,360
Gas Pipeline Integrity Mgmt. (DIMP)				49.021	7,785
PSEP				83,110	35,910
SoCalGas Only - SIMP				28,103	
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,178,640	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				49,671	6,361
PSEP				27,391	
Advanced Metering Infrastructure		Report	0	21,750	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,270	1,545
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	7,358	25,492	1,834
Annual Earning Assessment (AEAP)		CPUC Decisions	612	258	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	48,562	0
Haz Substance Mechanism (HSM)		CPUC Decisions	91,470	4,223	580
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	15,658	0
Core Pricing Flexibility Program		CPUC Decisions	0	1,619	0
Non-core competitive load growth program		CPUC Decisions	0	2,266	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	(76,948)	43,780	10,313
CPUC Fee	PUC Section 431	Resolution M-4816	11,661	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,849	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	7,047	20,492	2,521
AB 32 Cap-And-Trade			25,403	9,264	615
GHG Program			38,903	307,536	8,303
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**262,036**	**357,877**	**31,055**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	64,668	102,319	10,996
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	78,343	131,837	6,436
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,092	14,136	1,258
Calif Alternate Rates for Energy (CARE) Program			107,933	109,585	12,365
GAS TOTAL			**4,587,569**	**5,042,690**	**666,198**

Appendix B (cont.)

2018 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**879,270**	**1,048,393**	**139,506**
Core Gas Supply Portfolio		CPUC Decisions	517,473	1,037,040	139,506
Other		CPUC Decisions	362,041	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	(3,316)	0	0
Incentive Mechanism		Report	3,072	11,353	0
Transportation Total			**3,343,689**	**2,741,585**	**373,133**
Distribution		CPUC Decisions	1,964,824	2,331,772	325,765
Transmission		CPUC Decisions	1,281,236	0	0
Advanced Metering Infrastructure		Report	0	31,780	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	24,405	2,317
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	6,722	13,862	1,638
Annual Earning Assessment (AEAP)		CPUC Decisions	182	638	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	52,872	0
Haz Substance Mechanism (HSM)		CPUC Decisions	83,469	1,396	520
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	12,924	0
Core Pricing Flexibility Program		CPUC Decisions	0	784	0
Non-core competitive load growth program		CPUC Decisions	0	1,795	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	10,526	28,610	6,261
CPUC Fee	PUC Section 431	Resolution M-4816	7,837	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	5,102	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	5,842	22,589	2,057
AB 32 Cap-And-Trade			19,677	6,461	614
GHG Program	Sections 95851 (b), and 95852 (c) of Title 17	CPUC Decisions	(54,718)	-	-
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**248,026**	**323,410**	**33,186**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	57,823	74,527	11,931
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	75,742	129,252	16,002
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,840	13,294	1,203
Calif Alternate Rates for Energy (CARE) Program			103,621	106,337	4,050
GAS TOTAL			**4,470,985**	**4,113,388**	**545,825**